SIMULATION ASSESSMENT OF CO_2 SEQUESTRATION POTENTIAL AND ENHANCED METHANE RECOVERY IN LOW-RANK COALBEDS OF THE WILCOX GROUP, EAST-CENTRAL TEXAS

A Thesis

by

GONZALO HERNANDEZ ARCINIEGAS

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

August 2006

Major Subject: Petroleum Engineering

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Approved by:

Chair of Committee,	Duane A. McVay
Committee Members,	Walter B. Ayers, Jr
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ABSTRACT

Simulation Assessment of CO_2 Sequestration Potential and Enhanced Methane Recovery in Low-Rank Coalbeds of the Wilcox Group, East-Central Texas. (August 2006)

Gonzalo Hernandez Arciniegas, B.S., Universidad Surcolombiana, Colombia

Chair of Advisory Committee: Dr. Duane A. McVay

Carbon dioxide (CO_2) from energy consumption is a primary source of greenhouse gases. Injection of CO_2 from power plants in coalbed reservoirs is a plausible method for reducing atmospheric emissions, and it can have the additional benefit of enhancing methane recovery from coal. Most previous studies have evaluated the merits of CO_2 disposal in high-rank coals. Low-rank coals in the Gulf Coastal plain, specifically in Texas, are possible targets for CO_2 sequestration and enhanced methane production.

This research determines the technical feasibility of CO_2 sequestration in Texas low-rank coals in the Wilcox Group in east-central Texas and the potential for enhanced coalbed methane (ECBM) recovery as an added benefit of sequestration. It includes deterministic and probabilistic simulation studies and evaluates both CO_2 and flue gas injection scenarios.

Probabilistic simulation results of 100% CO_2 injection in an 80-acre 5-spot pattern indicate that these coals with average net thickness of 20 ft can store 1.27 to 2.25 Bcf of CO_2 at depths of 6,200 ft, with an ECBM recovery of 0.48 to 0.85 Bcf. Simulation results of 50% CO_2 - 50% N_2 injection in the same 80-acre 5-spot pattern indicate that these coals can store 0.86 to 1.52 Bcf of CO_2, with an ECBM recovery of 0.62 to 1.10 Bcf. Simulation results of flue gas injection (87% N_2 - 13% CO_2) indicate that these same coals can store 0.34 to 0.59 Bcf of CO_2, with an ECBM recovery of 0.68 to 1.20 Bcf.

Methane resources and CO_2 sequestration potential of low-rank coals of the Wilcox Group Lower Calvert Bluff (LCB) formation in east-central Texas are significant. Resources from LCB low-rank coals in the Wilcox Group in east-central Texas are estimated to be between 6.3 and 13.6 Tcf of methane, with a potential sequestration capacity of 1,570 to 2,690 million tons of CO_2. Sequestration capacity of the LCB low-rank coals in the Wilcox Group in east-central Texas equates to be between 34 and 59 years of emissions from six power plants in this area.

These technical results, combined with attractive economic conditions and close proximity of many CO_2 point sources near unmineable coalbeds, could generate significant projects for CO_2 sequestration and ECBM production in Texas low-rank coals.

DEDICATION

To God and my family

ACKNOWLEDGEMENTS

I would like to thank Ecopetrol, my sponsor company.

I am grateful to my committee chair, Dr. Duane A. McVay, and my committee members, Dr. Walter B. Ayers, Jr. and Dr. Wayne M. Ahr, for their guidance and support throughout the course of this research.

Thanks also to the Petroleum Engineering faculty professors who have taught me during my studies.

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TABLE OF CONTENTS

LIST OF FIGURES

FIGURE Page

FIGURE Page

FIGURE Page

FIGURE Page

LIST OF TABLES

CHAPTER I

INTRODUCTION

1.1. General Problem Statement

The gradual warming of the earth's surface due to increased entrapment of solar radiation in the atmosphere is known as the greenhouse effect. The most important greenhouse gases (GHG) that contribute to this effect are water vapor (H_2O), carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), tropospheric ozone (O_3), and man-made chlorofluoro-carbons, with CO_2 accounting for 63.6% of the relative contribution. The primary CO_2 source is emissions from coal combustion for electricity generation, which is the largest source of energy from the earth.[1]

Anthropogenic GHG emissions have potentially contributed to global warming during the last few decades. CO_2 sequestration in geological formations such as coal seams is a promising option for reducing atmospheric emissions while fossil fuels are still being used[2] and, at the same time, enhancing methane recovery. CO_2 injection accelerates coalbed methane production, reducing the cost of a sequestration project.

1.2. Previous Work

CO_2 sequestration/ECBM production has been investigated in high-rank coals. Reservoir simulation studies and field tests are being conducted to assess CO_2 sequestration potential and ECBM recovery in these coals. Below, I will discuss the characteristics of coal reservoirs, the CO_2 sequestration/ECBM recovery process, key coal properties and field tests conducted in the San Juan basin in high-rank coals.

This thesis follows the style and format of the *SPE Journal.*

Coal natural gas reservoirs are considered to be dual-storage systems.[3] Coalbed methane reservoirs are typically modeled with dual-porosity/single-permeability characteristics when forecasting well or field performance. The relatively impermeable primary porosity system is dominated by adsorption/desorption phenomena, and mass transfer is controlled by diffusion, driven by gas-concentration gradients. The secondary porosity system is dominated by natural fractures, and flow through fractures is driven by pressure gradients between the fracture system and the production wells.[1] Thus, coal-gas reservoirs are characterized by matrix (coal) and fracture (cleat) systems. In the production process with lowering of fluid pressure, gas desorbs from the coal into the matrix porosity, diffuses through the bulk matrix, and then flows into and through the fractures. During CO_2 injection for carbon sequestration, the pathway for CO_2 sorption is exactly reversed.[2]

The CO_2 sequestration/ECBM recovery process takes place when methane in the primary storage system is replaced with CO_2, which adsorbs preferentially to the coal as compared to methane. This process increases methane production and stores CO_2 in the coal. A sequestration project typically terminates when CO_2 breaks through at the production wells after the majority of the well pattern has been swept.

Knowledge of (1) sorption capacity, or isotherm behavior, of gaseous species and, (2) coal permeability changes with gas injection are critical for better understanding of CO_2 sequestration/ECBM recovery processes.

Bromhal *et al.*[4] evaluated the effects of sorption isotherms on CO_2 sequestration in coalbeds. The isotherm behavior is described by the Langmuir isotherm model to predict the amount of adsorbed/desorbed gas as a function of pressure. They concluded that not all of the in-situ methane will be produced and not all of the theoretical sequestration capacity will be used because CO_2 will not reach all portions of the coal seam.

In naturally fractured formations such as coal, permeability is sensitive to changes in effective stress. In coalbed methane reservoirs, matrix shrinkage or swelling occurs as a result of desorption or adsorption of gaseous species, which affects coal porosity and permeability. Palmer and Mansoori[5] developed a model to calculate how absolute permeability and fracture porosity change as pressure decreases or increases in a reservoir, accounting for two important effects at the same time, stress-dependent permeability and matrix shrinkage/swelling.

Reservoir simulators are being improved to include features that account for coal-matrix swelling from CO_2 adsorption on coal, mixed-gas adsorption/desorption and diffusion, compaction/dilation of the natural fracture system under stresses, and nonisothermal effects for gas injection. A comparison[6] of numerical simulators for ECBM recovery with pure CO_2 injection identified areas of improvement required to correctly model complicated mechanisms involved in the ECBM recovery process.

The ECBM recovery process is being investigated in two field projects in the San Juan basin of New Mexico. One is the Allison Unit, operated by Burlington Resources Inc., into which CO_2 is being injected, and second is the Tiffany Unit, operated by BP America Inc., into which N_2 is being injected.[7] These projects, funded by the Department of Energy (DOE) in a collaboration agreement with industry, are testing the process in high-rank coalbeds.

No field project currently is attempting to sequester CO_2 in low-rank coalbeds. The U.S. Department of Energy and Anadarko Petroleum Corporation are funding a research project investigating the CO_2 sequestration potential of Texas low-rank coals. A preliminary modeling study[8] using assumed permeability, CO_2 storage, and methane content values concluded that 360 wells on 80-acre well spacing could sequester CO_2 emissions for the Gibbons Creek plant for 11 years, while producing 90 Bcf of methane.

These results were considered speculative because reservoir properties were poorly known.

As part of this study, additional reservoir data were collected from the Wilcox Group coals in east-central Texas. These data consist of desorption analyses for determining gas content, adsorption/desorption isotherms for CH_4, CO_2 and N_2, and in-situ fracture permeability estimates from well tests. These data were used to improve coal reservoir characterization and reservoir simulation to assess the potential for CO_2 sequestration in, and enhanced methane production from, Texas low-rank coals.

1.3. Objectives of Study

The main objectives of this research were to:

- Determine the technical feasibility of CO_2 sequestration in low-rank coals in the Wilcox Group in east-central Texas.
- Determine the potential for enhanced methane recovery from low-rank coalbeds in the Wilcox Group in east-central Texas as an added benefit of sequestration.
- Evaluate the effects of well spacing, injection gas composition, injection rate, coal dewatering prior to CO_2 injection, and permeability anisotropy on CO_2 sequestration.
- Quantify uncertainty in potential CO_2 sequestration in, and methane production from, low-rank coals in the Wilcox Group in east-central Texas.

1.4. Scope of the Work

This research included a parametric simulation study based on a pattern model using reservoir characteristics of the Wilcox Group low-rank coals in east-central Texas.

Reservoir simulation was coupled with Monte-Carlo simulation to conduct probabilistic reservoir simulation modeling studies consisting of thousands of simulation runs to quantify the uncertainty in my forecasts of CO_2 sequestration and methane production.

1.5. Motivation

Results of this research show the potential for CO_2 sequestration/ECBM recovery in low-rank coals. Abundant low-rank coals in the Gulf Coastal plain, specifically in Texas, could be possible targets for CO_2 sequestration and enhanced methane production. Close proximity of many CO_2 point sources near unmineable coalbeds could generate significant CO_2 sequestration and ECBM potential in Texas low-rank coals. Additionally, there are numerous low-rank coal deposits is the U.S. This project could identify a new resource of energy by extension of this application to other low-rank coals.

CHAPTER II

SURVEY OF CO_2 EMISSIONS IN TEXAS AND AREA OF STUDY

2.1. CO_2 Emissions in Texas

Greenhouse gas emissions potentially contribute to global warming. CO_2 from energy consumption is a primary source of greenhouse gases. Texas power plants emitted more CO_2 in 2002 than those in any other state. The amount of CO_2 emitted in 2002 from combustion of fossil fuels (gas, lignite, and coal) by the 78 major power plants in Texas was about 248,808,000 tons,[9] which accounted for 12% of the total CO_2 emissions from coal in the U.S.

Fig. 2.1 shows the amount of CO_2 emitted and fuel type by power plant for the 20 largest Texas CO_2 emitters. Fig. 2.2 depicts the relative contribution of CO_2 emissions from the top 20 power plants in Texas.

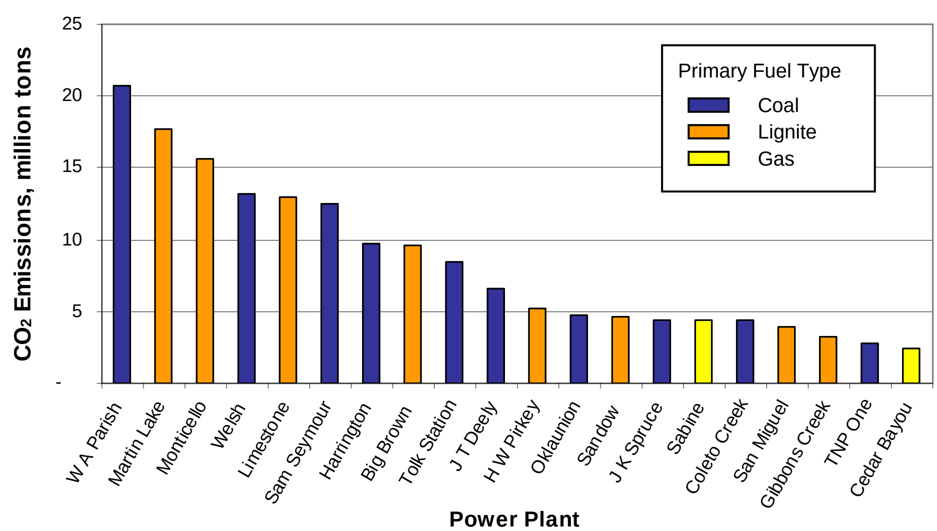


Fig. 2.1 CO_2 emissions from the top 20 power plants in Texas, 2002.[9]

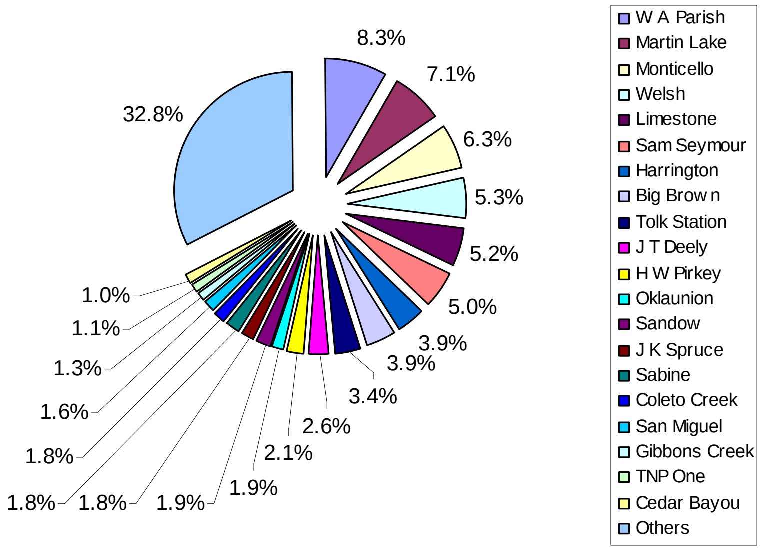


Fig. 2.2 Relative CO_2 emissions from the 20 largest power plants in Texas, 2002.[9]

A map of Texas showing the Wilcox Group outcrop and locations of the 20 largest electrical generating plants in terms of the quantities of CO_2 emitted is shown in Fig. 2.3.

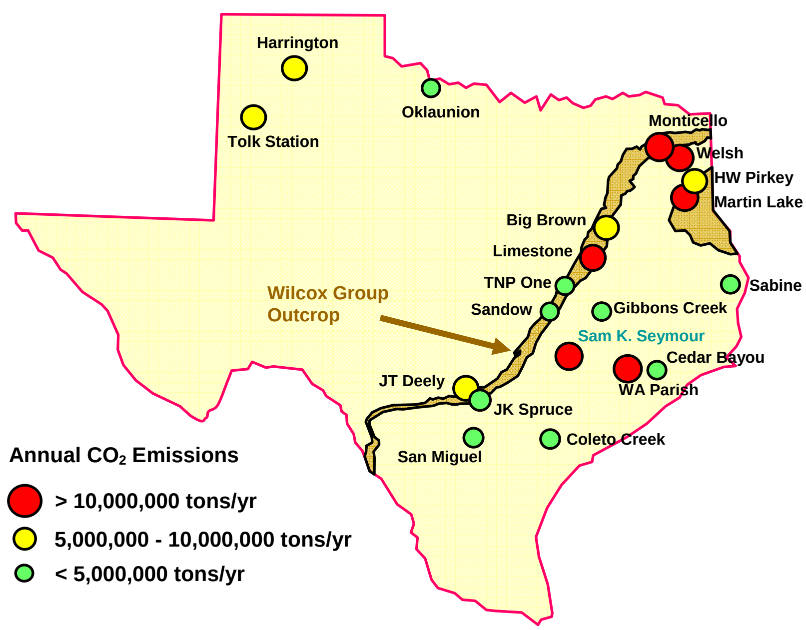


Fig. 2.3 Wilcox Group outcrop and locations of the 20 largest Texas CO_2 emitters, 2002.

2.2. Selection of the Study Area

The extensive low-rank coal deposits that occur in the Hooper, Simsboro, and Calvert Bluff formations of the Wilcox Group were mapped throughout east-central Texas in the 1980s by Ayers and Lewis.[10] Fig. 2.4 shows outcrops of Tertiary coal-bearing strata of the Wilcox Group, Yegua Formation, and Jackson Group in the Texas Gulf Coastal Plain. Outcrop belts are subparallel to the coast. The Wilcox Group also crops out in the Sabine Uplift.[11]

In many areas of east-central Texas, low-rank coals host mine-site electric power plants. Proximity of Texas power plants to abundant, well-characterized coal deposits make this area ideal to assess the viability of CO_2 sequestration in low-rank coals and to test technology that may be transferable to other low-rank coals of the U.S. and the world.

Coalbeds in the Lower Calvert Bluff (LCB) formation of the Wilcox Group were identified as the primary targets for CO_2 sequestration and ECMB production.[12,13] It was determined that additional data were needed to characterize the coal reservoir properties. These data needs included analyses of core samples to determine coal and gas properties and well tests for determining coal fracture permeability.

I focused my investigation of CO_2 sequestration potential on low-rank coals of the Wilcox Group in east-central Texas owing to the (1) relatively high CO_2 emissions near potential injection sites in thick Wilcox coals, (2) location basinward of the Wilcox freshwater zone, and importantly, (3) Anadarko’s database of existing samples and their interest in collecting additional data.[13]

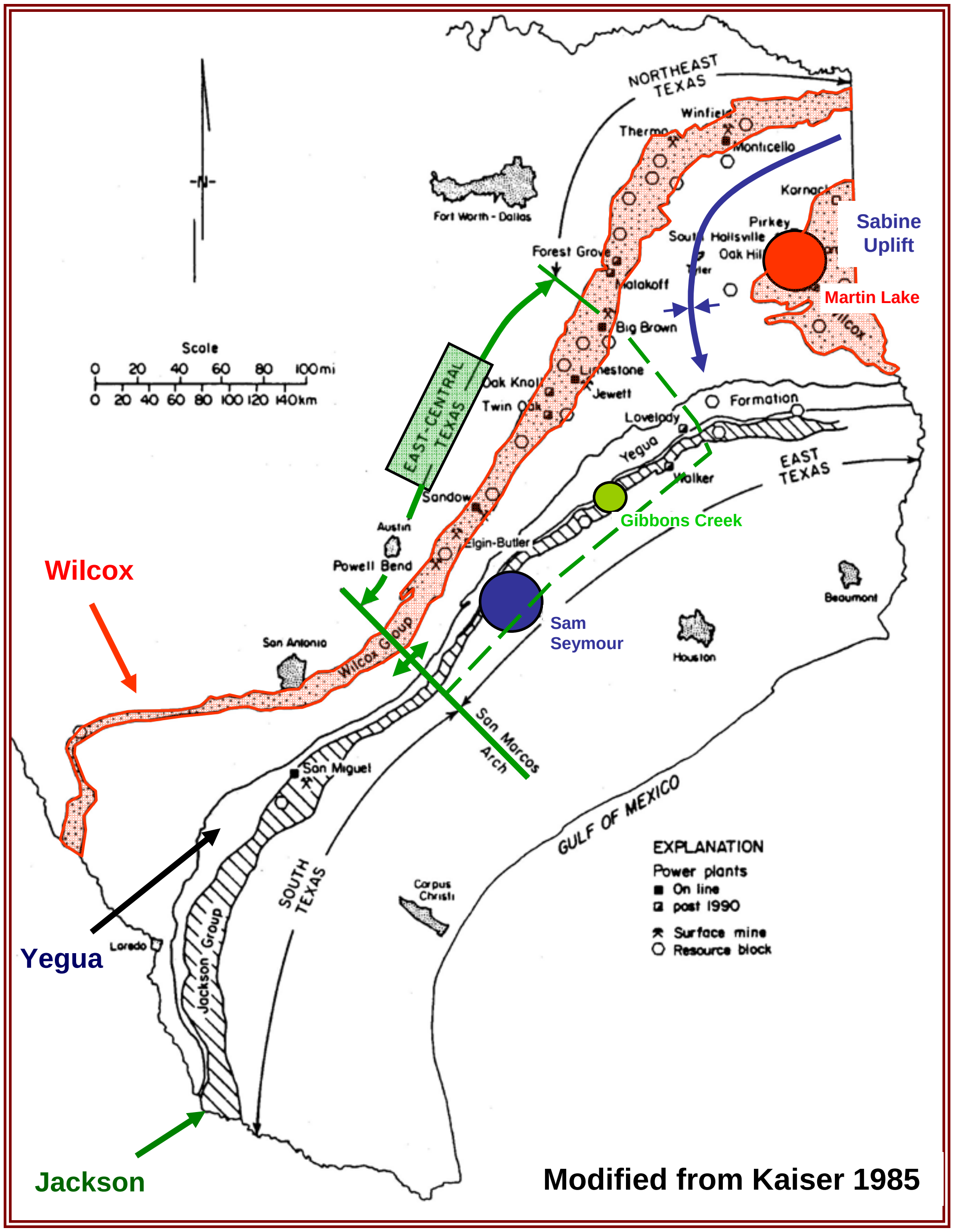


Fig. 2.4 Outcrops of Texas coal-bearing units, showing lignite mines and selected power plants.[11]

CHAPTER III

WILCOX GROUP COAL RESERVOIR CHARACTERIZATION

To improve coal reservoir characterization near CO_2 emitters, sidewall core samples were collected from Calvert Bluff coals in the vicinity of Sam K. Seymour power plant in Fayette County, Texas, one of major point-source emitters of CO_2 in east-central Texas. The samples were used for desorption analysis to determine gas content, gas compositional analysis, sorption isotherms for CO_2, CH_4, and N_2, coal quality analysis, and vitrinite reflectance. Pressure injection/falloff tests were conducted in two Calvert Bluff coal seams to determine in-situ fracture permeability. These new data are key to completing the Wilcox coal reservoir simulation model.

3.1. Coal Quality, Gas Content and CH_4, CO_2, and N_2 Isotherms

Analyses of the composite sample of 10 sidewall cores from an Anadarko Petroleum Corporation cooperative well (APCL2)[14] indicate average values of 4.53% moisture content, 37.48% volatile matter, 9.86% ash, 48.12% fixed carbon, sulfur content of 1.31%, and a heating value of 12,405 BTU/lb, as received. Vitrinite reflectance (Ro) of the composite coal sample, which was measured over a 144-ft depth interval (6,118-6,262 ft), ranged between 0.47% and 0.61%; mean value was 0.54%. Coal rank is borderline between high-volatile C and high-volatile B bituminous. Bulk density measurements of the APCL2 sidewall core samples averaged 1.332 g/cc, whereas average coal density from well logs was 1.350 g/cc.

The total desorbed and estimated lost gas content of 10 coal samples from Well APCL2 that were desorbed in 4 canisters, based on a polynomial fit for lost gas, ranged from 365 to 429 scf/ton, with an average total gas content of 395 scf/ton (as-received) (Table 3.1). The lost gas estimations for the samples were 43% to 47% of the total gas and averaged approximately 45%. A study conducted by Hampton, Waechter & Associates (HWA)[14] for Anadarko concluded that estimated values of lost gas may be inaccurate owing to the long retrieval time (49 minutes), fluctuation of ambient temperature, and/or high diffusivity of the coal. Projected residual gas was approximately 5% of in-situ gas content. These measured gas values corroborate previous Anadarko test results and indicate significant methane resources in deep Wilcox coals.

Table 3.1 Gas content of 10 sidewall cores coal samples from the LCB formation of the Wilcox Group.[14]

Canister #	Coal Bed		(1) Lost Gas (scf/ton)	(2) Lost + Measured Gas (scf/ton)	(3) Total Gas (scf/ton)
	Top (MD, ft)	Bottom (MD,ft)			
1	6112	6114	195.2	411.3	429.3
2	6116	6118	161.6	362.7	365.0
3	6148	6152	174.5	392.1	407.5
4	6264	6274	179.8	359.0	382.1
Sidewall Core Averages			177.2	375.6	394.8

(1) Lost Gas content using polynomial fit
(2) With out Residual Gas
(3) Lost + Measured + Projected Residual Gas

Six gas samples desorbed from the sidewall cores retrieved from the APCL2 well were analyzed. Average gas composition was 94.3% methane, 3.0% ethane, and 0.7% propane, with traces of heavier hydrocarbons. Carbon dioxide averaged 1.7% in the coalbed gas.

The volumes of CH_4 recovered and CO_2 sequestered depend on the sorption properties, which are determined from isotherms. CO_2, CH_4, and N_2 sorption isotherms of LCB coal samples from approximately 6,200-ft depth in the APCL2 well were measured in the laboratory[15] (Fig. 3.1). Langmuir volume and pressure on an as-received basis are 961.9 scf/ton and 697.5 psia, respectively, for CO_2, 363.6 scf/ton and 608.5 psia for CH_4, and 166.1 scf/ton and 2060.7 psia for N_2. These isotherm data were used to model variable injected gas composition.

Comparison of the desorbed gas content values with the methane isotherm (as received) for the APCL2 well indicates that the Wilcox coals tested from this well are saturated with methane and should require no depressurization to initiate gas production. However, the fact that estimated total methane content at reservoir temperature and pressure plots above the isotherm suggests that, as noted by HWA,[14] the lost gas component may have been overestimated. Therefore, I also plotted measured and calculated residual gas content only for comparison (Fig. 3.1).

These sorption isotherms[15] for CO_2, CH_4, and N_2 were measured to maximum pressures of 595, 3142, and 2767 psia, respectively, at 168°F. Ideally, isotherms would have been measured from 0 psia to pressures greater than reservoir pressure, which is approximately 2,680 psi, assuming a freshwater hydrostatic gradient of 0.432 psi/ft and average depth of 6,200 ft.

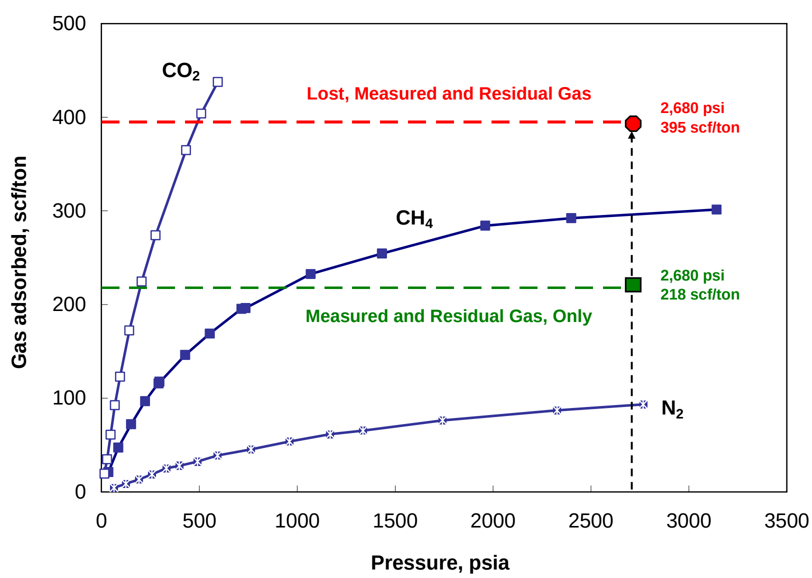


Fig. 3.1 CO_2, CH_4 and N_2 adsortion/desorption isotherms for coals at 6,200-ft depth in east-central Texas, showing measured plus residual and total gas content (lost, measured, and residual) determined for 10 sidewall cores in the APCL2 well (as received basis).

Adsorption isotherms for pure CO_2 (3 samples) and CH_4 (4 samples) for Wilcox coals are shown in Fig. 3.2, while the relationships of CO_2 vs. CH_4 sorptive capacities are shown in Fig. 3.3. At 1,000 psia (projecting the CO_2 curve), the ratio of CO_2:CH_4 sorptive capacity is about 2.5:1. This ratio is low in comparison to laboratory results for Wilcox coals from the Sandow surface mine and from the U.S. Geological Survey's (USGS) Panola County well.[16] In the Sandow and PA/CN2 cases, as with other adsorption studies of low-rank coals by the USGS, the CO_2:CH_4 ratio was approximately 10:1. Based on USGS and Sandow mine analyses, Garduno *et al.*[8] had used a 10:1 ratio of CO_2:CH_4 in preliminary reservoir modeling for this study. The 2.5:1 ratio obtained for the APCL2 samples is similar to results from bituminous coals in other basins.[17] However, those results were for much higher rank coals than those of the Wilcox Group in the APCL2 well. This result (2.5:1 storage capacity), based on only the APCL2 well, suggests that Wilcox coals in this area will sequester less CO_2 per ton of coal than anticipated on the basis of earlier studies (10:1 storage capacity). Moreover, because measured methane contents are higher, enhanced coalbed methane production potential should be greater than was earlier predicted.[8]

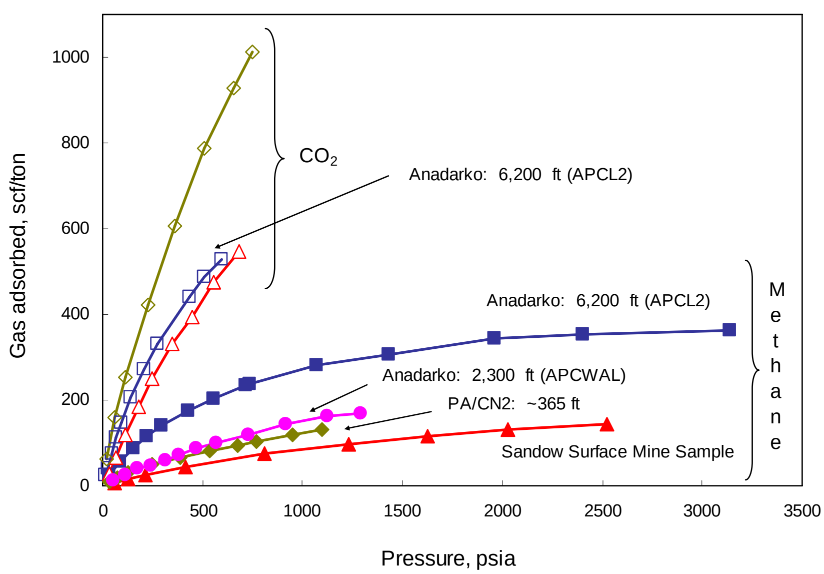


Fig. 3.2 Comparison of CH_4 and CO_2 adsorption isotherms for Wilcox coal samples from one surface mine and 3 east-central Texas wells (dry, ash-free basis).

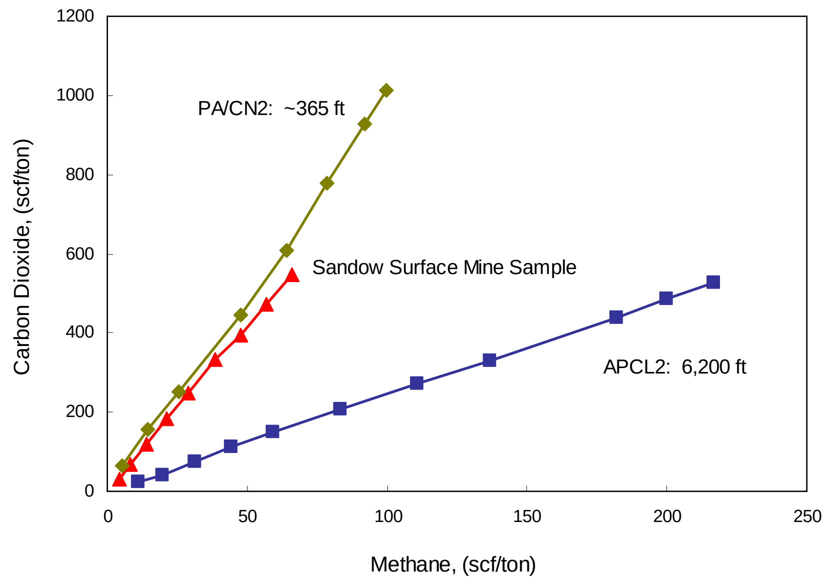


Fig. 3.3 CO_2 vs. CH_4 sorptive capacities relationship for Wilcox coal samples from one surface mine and 2 east-central Texas wells (dry, ash-free basis).

Depth relations between vitrinite reflectance and methane storage capacity determined from isotherms are shown in Figs. 3.4 and 3.5, using Wilcox coal data from the Sandow surface mine, the PA/CN2 (365 ft deep) well, the APCWAL (2,300 ft deep) well, and the APCL2 (6,200 ft deep) well, on a dry ash-free basis. As expected, vitrinite reflectance and methane sorptive capacity increase with depth and thermal maturity.

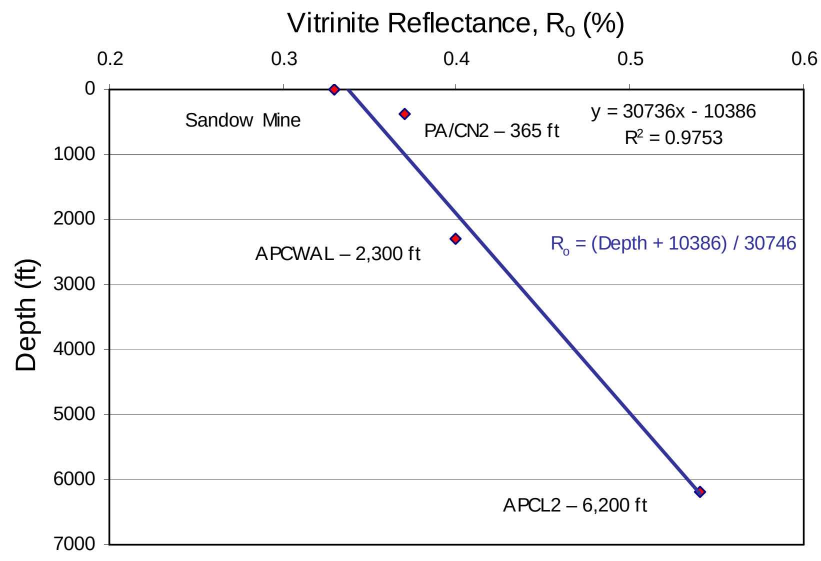


Fig. 3.4 Vitrinite reflectance of Wilcox coals increases with depth in east-central Texas.

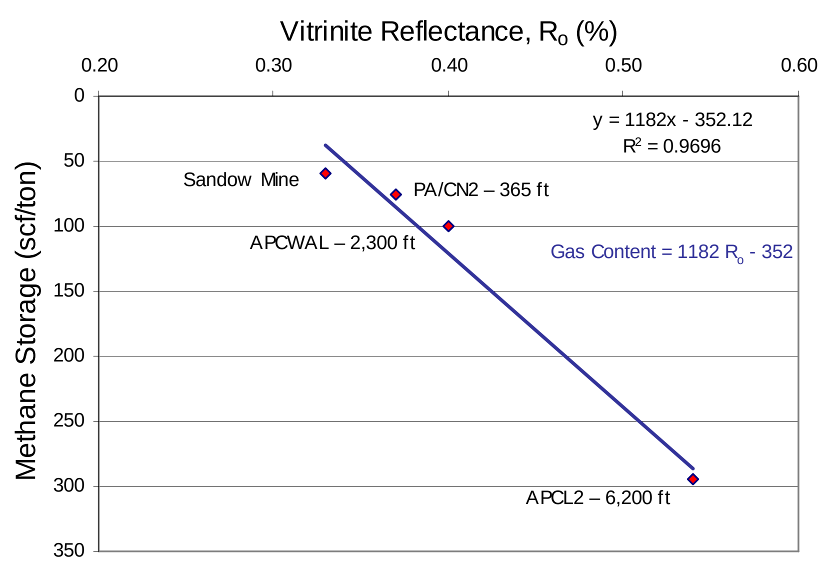


Fig. 3.5 In east-central Texas, methane storage capacity of Wilcox coals is related to vitrinite reflectance.

A comparison of CO_2/CH_4 sorption capacity ratios for coal samples from two surface mines and 12 wells is presented in Fig. 3.6. Vitrinite reflectance ranges from 0.33% to 1.40% for coals from the Gulf Coast, Powder River, Forest City, Illinois, N. Appalachian, Cherokee, Piceance, Warrior, and San Juan Basins.[18] For the 6,200-ft depth Wilcox coal sample, CO_2/CH_4 ratio is approximately 2.5.

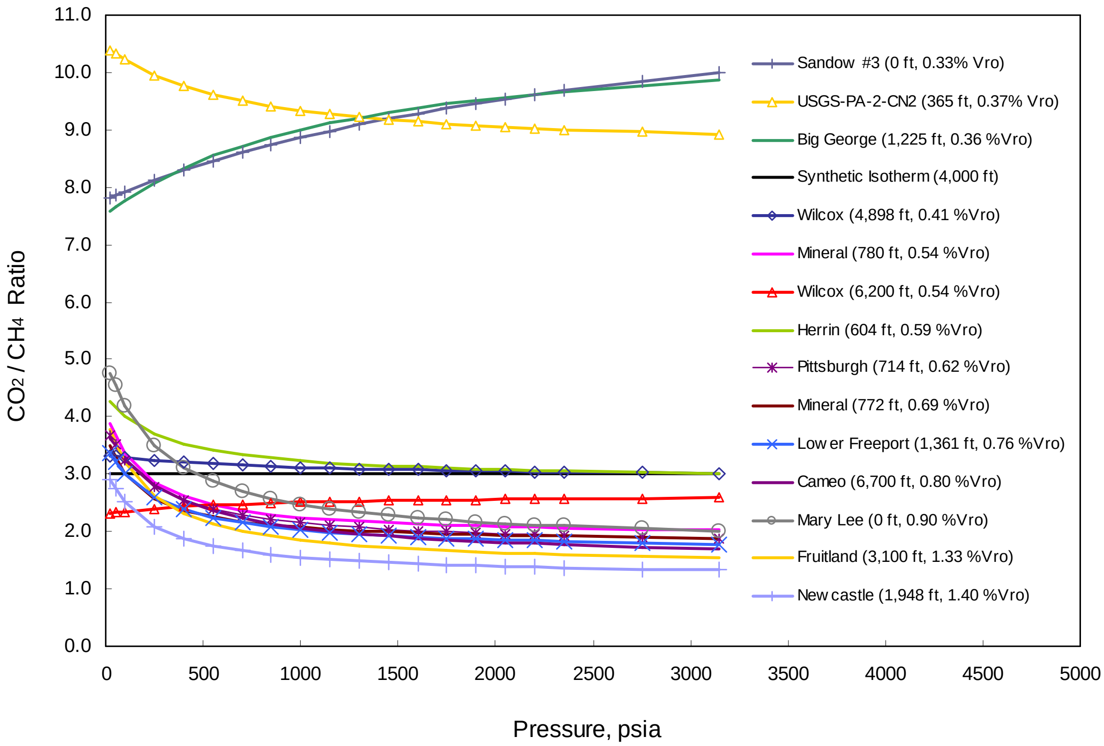


Fig. 3.6 Carbon dioxide/methane sorption capacity ratios for U.S. coal samples from two surface mines and 12 wells.

A comparison of N_2/CH_4 sorption capacity ratios for coal samples from one surface mine and 11 wells is presented in Fig. 3.7. Vitrinite reflectance ranges from 0.36% to 1.40% for coals from the Gulf Coast, Powder River, Forest City, Illinois, N. Appalachian, Cherokee, Piceance, Warrior, and San Juan Basins.[18] For the 6,200-ft depth Wilcox coal sample, N_2/CH_4 ratio is approximately 0.32 at reservoir pressure of 2,680 psia, and decreases as pressure declines.

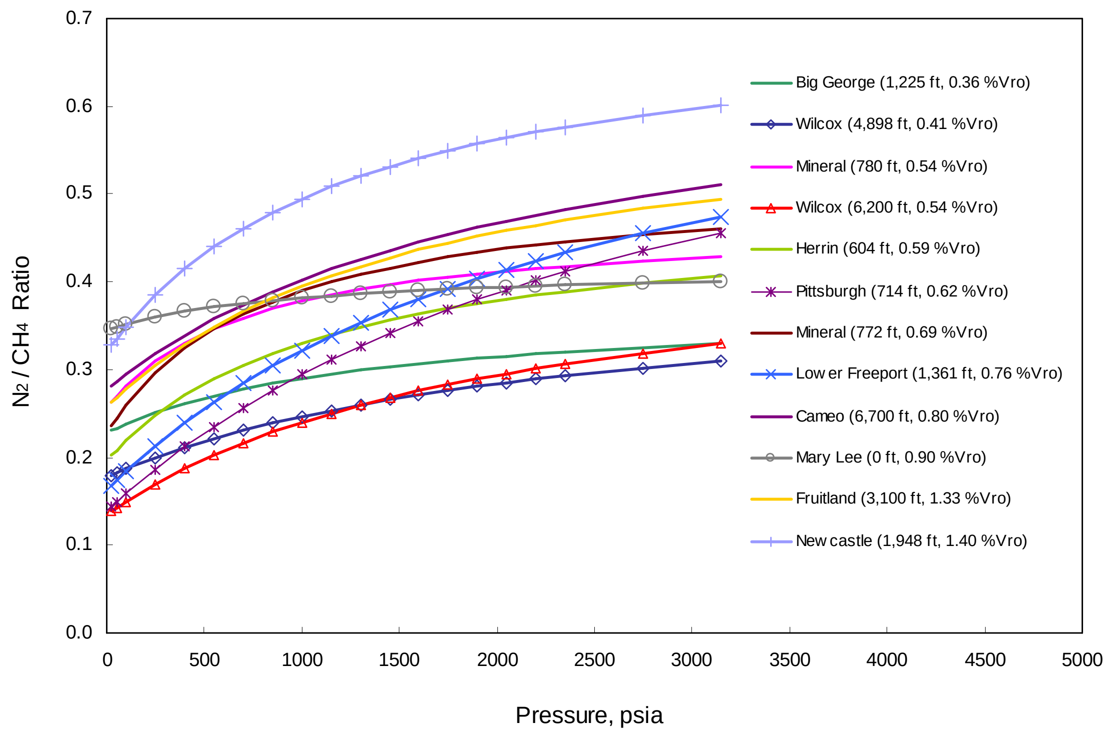


Fig. 3.7 Nitrogen/methane sorption capacity ratios for U.S. coal samples from one surface mine and 11 wells.

Synthetic isotherm data were constructed to model coalbed reservoirs in the 4,000-ft depth range. Fig 3.8 shows CH_4 sorption isotherms from 7 wells and one surface mine coal sample. The Anadarko 2,300-ft and 5,400-ft isotherms were used to interpolate CH_4 sorption values. CO_2/CH_4 sorption ratio of approximately 3:1, which was the ratio from coal samples at approximately 4,900-ft depth in the Wilcox Group in Louisiana,[18] was used to estimate CO_2 sorption values. N_2/CH_4 sorption ratio of approximately 0.27:1 at reservoir pressure of 1720 psia and decreasing ratios as a function of pressure, which was the relation from coal samples at approximately 4,900-ft depth in the Wilcox Group,[18] was used to estimate N_2 sorption values. Langmuir volume and pressure parameters on an as-received basis for the synthetic isotherm for coals at approximately 4,000-ft depth were estimated to be 458.5 scf/ton and 1884.0 psia for CH_4, 1375.5 scf/ton and 1884.0 psia for CO_2, and 301 scf/ton and 6764 psia for N_2 (Fig. 3.9).

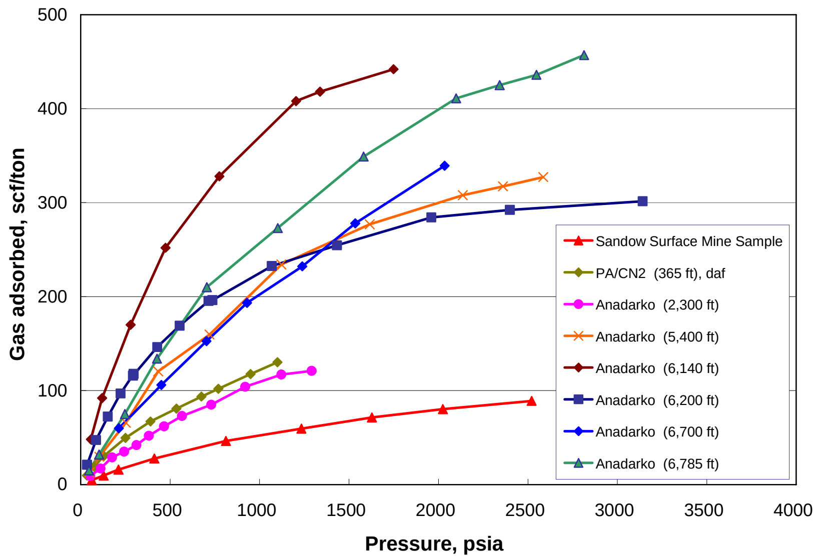


Fig. 3.8 Methane adsorption isotherms for the Wilcox coal samples from one surface mine and 7 east-central Texas wells.

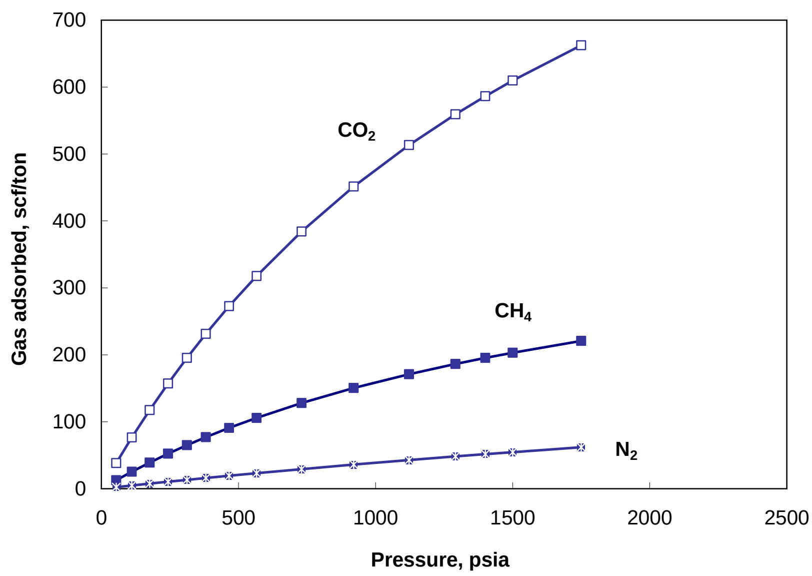


Fig. 3.9 CO_2, CH_4 and N_2 adsortion/desorption synthetic isotherms for coals at 4,000-ft depth in east-central Texas (as received basis).

3.2. Wilcox Coals Permeability Estimation from Well Tests

Permeability, as well as skin factor and reservoir pressure, is a critical parameter affecting the extraction of gas from coalbeds.[19] Wilcox coal reservoir characterization included determination of absolute coal fracture permeability from two LCB low-rank coals perforated in the Anadarko APCT2 well.

Water injection/fall-off pressure transient tests are recommended to best determine permeability in coalbed reservoirs,[20] as opposed to withdrawing fluids from the formation, which may result in methane desorption. Well test analysis becomes difficult in the presence of two-phase flow conditions and the combined mechanisms of diffusion and gas flow in porous media.

Pinnacle Technologies conducted two injection/falloff tests in the APCT2 well, with the objective of determining in-situ permeability to water in multiple perforated intervals. Low-rate equipment specially designed for testing coalbed methane reservoirs was used to conduct the injection/falloff tests. Bottom-hole pressures were measured in both well tests performed, while surface injection rates were measured at the injection unit. Maximum fracture gradients based on breakdowns pumped prior to the injection tests were used to determine maximum surface injection pressure.[21]

Data from both injection/falloff tests were of good quality, and their interpretation results are presented in Table 3.2. The first injection/falloff test was conducted in one coal seam with perforated thickness of 7 ft at approximately 4,200-ft depth. Semi-log analysis of the pressure falloff data resulted in coal seam permeability to water of 1.9 md, a skin factor of -4.9, and an average reservoir pressure of 1,851 psi (Fig. 3.10). Average reservoir pressure is equivalent to a gradient of 0.44 psi/ft. The reservoir temperature was estimated to be 145^{o}F.

The second injection/falloff test was conducted in one coal seam with perforated thickness of 3 ft at approximately 4,000-ft depth. Semi-log analysis of the pressure falloff data resulted in coal seam permeability to water of 4.2 md, a skin factor of -1.9, and an average reservoir pressure of 1,687 psi (Fig. 3.11). Average reservoir pressure is equivalent to a gradient of 0.43 psi/ft. The reservoir temperature was estimated to be 140^{o}F.

In both tests, negative skin factors indicate that the tested zones are stimulated, most likely a combined result of open cleats, perforating activities, and the injection tests creating microfractures near the wellbore.

Table 3.2 Interpretation results of the pressure injection/falloff tests conducted in the Wilcox coals.

Depth, ft	4,200	4,000
Permeability, md	1.9	4.2
Skin factor	-4.9	-1.9
Pressure, psia	1,851	1,687

The permeability values obtained from these two tests are in the lower part of the range of permeability used in the preliminary simulation model (1.0, 5.0, and 20.0 md).[8] The geometric mean of these permeability data is 2.8 md. A log-normal distribution derived from the calculated permeability data is used as input in the reservoir simulation model.

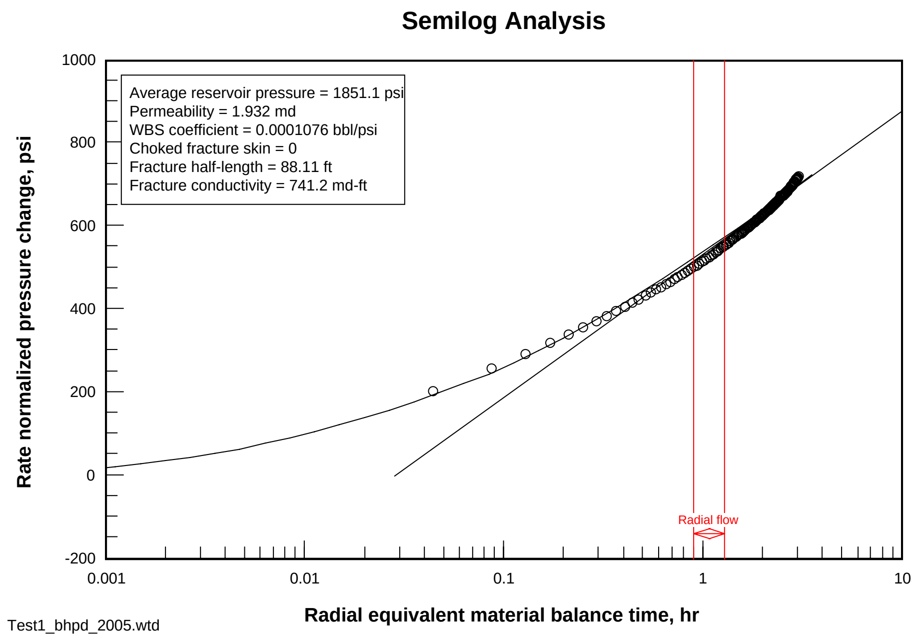


Fig. 3.10 Pressure falloff interpretation for the first coal seam test, from Well APCT2 at approximately 4,200 ft depth in the Wilcox Group.

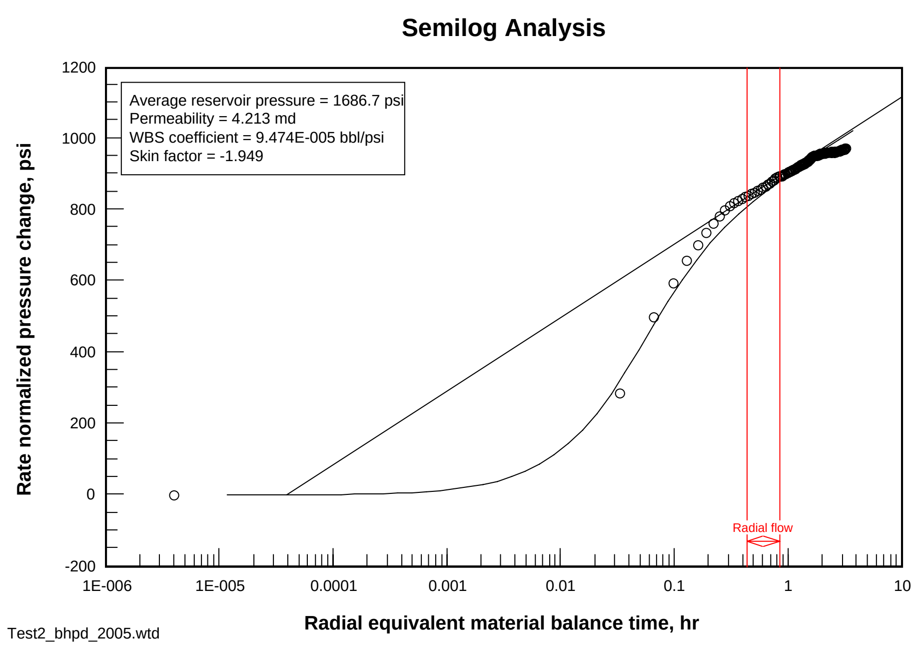


Fig. 3.11 Pressure falloff interpretation for the second coal seam test, from Well APCT2 at approximately 4,000-ft depth in the Wilcox Group.

CHAPTER IV

RESERVOIR SIMULATION MODEL

4.1. Simulation Approach

Important considerations in modeling CO_2 sequestration/ECBM production are mentioned here. In general, commercial and research CBM simulators are developed to model primary recovery processes taking into account important features to properly evaluate the performance of coalbed reservoirs. In order to correctly model complex reservoir mechanisms in the ECBM recovery process via CO_2 and/or N_2 injection, CBM simulators are being improved to account for additional features. Important features[6,22] in modeling primary and enhanced coalbed methane recovery processes are as follows:

- Dual porosity,
- Multiple gas components,
- Multiphase flow (gas and water) in the natural fracture system (Darcy flow),
- Pure and mixed gas diffusion between coal matrix and the natural fracture system (different diffusion rates),
- Pure and mixed gas adsorption/desorption at the coal surface (extended Langmuir isotherm relationship),
- Compaction/dilation of the natural fracture system due to stresses (stress-dependent permeability and porosity models),
- Coal matrix shrinkage/swelling due to gas desorption/adsorption (ability of gases to change coal structure),
- Non-isothermal adsorption of the injected gas, and
- Water effects on gas flow kinetics in coal matrix.

Capability to handle multiple gas components is an essential feature in modeling ECBM recovery processes with flue gas. Recent advances in numerical simulation for CBM/ECBM recovery processes focused on multi-component gas transport in in-situ bulk coal and changes of coal properties during methane production.[23]

Considering the required features for modeling ECBM recovery processes, the coalbed simulator GEM developed by Computer Modelling Group (CMG) Ltd. was selected to conduct deterministic and probabilistic simulation studies. GEM is a three-dimensional, finite-difference, multiphase, dual-porosity, compositional simulator. It has the option to select the Peng and Robinson equation of state (EOS) to calculate the necessary thermodynamic functions. The Palmer and Mansoori[5,24] model to calculate how absolute permeability and fracture porosity change as pressure decreases or increases in a reservoir is available in GEM. The simulator is capable of modeling coalbed methane reservoir performances under primary and/or enhanced recovery schemes.

I coupled reservoir simulation (GEM) with Monte-Carlo simulation (@RISK) to conduct probabilistic reservoir modeling studies consisting of thousands of simulation runs to quantify the uncertainty in my forecasts of CO_2 sequestration and methane production. Monte-Carlo simulation is a method to account for uncertainty in reservoir data, as well as technical risk assessment.

4.2. Reservoir Model Parameters

To assess CO_2 sequestration and ECBM production in the Wilcox Group Lower Calvert Bluff (LCB) coalbeds, I selected reservoir parameters representative of two scenarios: one at approximately 6,200-ft depth and the other at 4,000-ft depth. These are typical depths of potential LCB coalbed reservoirs in east-central Texas. Average coal properties and reservoir parameters obtained from literature and data collected during this study are shown in Tables 4.1 - 4.3.

Table 4.1 Coal static reservoir property estimates.

Property	**Value**
Fracture/Cleat Spacing	2.5 inches
Fracture Porosity	1%
Matrix Porosity	1%
Fracture Compressibility	138×10^{-6} 1/psi
Water Density	0.99 g/cm^3 (61.85 lb/ft^3)
Water Viscosity	0.607 cp
Water Compressibility	4.0×10^{-6} 1/psi
Initial Water Saturation	100%
Initial Composition of Gas in the Reservoir	100% CH_4

Table 4.2 Uncertain reservoir property estimates and design parameters.

Property/Parameter	**Value**
Coal Seam Thickness $^{(1)}$	10, 20, 30 ft
Fracture Absolute Permeability $^{(2)}$	0.8, 2.8, 10 md
Coal Density $^{(1)}$	1.289, 1.332, 1.380 g/cm^3 (80.5, 83.2, 86.2 lb/ft^3)
Gas Phase Diffusion Time$^{(1)}$ (Sorption Time)	0, 1, 4 days
Injection Gas Composition	100% CO_2, 13% CO_2 - 87% N_2, 50% CO_2 - 50% N_2
Well Spacing	40, 80, 160, 240 acres
$^{(1)}$ Triangular Distribution $^{(2)}$ Log-Normal Distribution	

Coal thickness. LCB average net coal thickness is 20 ft in the area of study.[10] A triangular distribution (10 ft, 20 ft, and 30 ft coal thickness) is used in the reservoir simulation model to help quantify uncertainty.

Coal porosity. Coal porosity of 1% is estimated to be a representative value in the study area. In dual porosity models,[25] fracture porosity is the fraction of void space in the fracture system in a volume of bulk reservoir rock. Matrix porosity is the fraction of void space in a piece of unfractured matrix material.

Table 4.3 Parameters for base case coal seam scenarios.

Property/Parameter	4,000-ft depth	6,200-ft depth
Initial Reservoir Pressure	1,730 psia	2,680 psia
Reservoir Temperature	140 ^oF	170 ^oF
Langmuir Isotherm Parameters $^{(1)}$:		
V_L, CH_4	458.5 scf/ton	363.6 scf/ton
P_L, CH_4	1,884 psia	608.5 psia
V_L, CO_2	1,375.5 scf/ton	961.9 scf/ton
P_L, CO_2	1,884 psia	697.5 psia
V_L, N_2	301 scf/ton	166.1 scf/ton
P_L, N_2	6,764 psia	2,060.7 psia
Operating Conditions - Pressure Control :		
Production Well, Pressure and Rate	40 psia, 3.5 MMscf/D	40 psia, 3.5 MMscf/D
Injection Well, Pressure and Rate	2,175 psia, 3.5 MMscf/D	3,625 psia, 3.5 MMscf/D
Operating Conditions Injection Rate Case - Pressure Control :		
Production Well, Pressure and Rate		500 psia, 3.5 MMscf/D
Injection Well, Pressure and Rate		3,165 psia, 3.5 MMscf/D
$^{(1)}$ As-received basis		

Fracture spacing. Coal fracture/cleat spacing was estimated to be approximately 2.5 inches on the basis of coal descriptions from Sandow, Big Brown, and Martin Lake surface mines.[26] Fracture spacings are used to calculate the matrix-to-fracture transfer coefficient as described by the shape factor type. Gilman & Kazemi (GK) and Warren & Root (WR) shape factor formulations are available options in calculating matrix-to-fracture flows within blocks for dual-porosity models in GEM.

Coal permeability. A log-normal distribution of coal fracture permeability based on well test results (1.9 to 4.2 md, with geometric mean of 2.8 md) is used in the reservoir simulation modeling.

Rock compressibility. A matrix compressibility of $1x10^{-6}$ psi^{-1} and a fracture compressibility of $138x10^{-6}$ psi^{-1} are used in the simulation model. Pore volume compressibility measurements reported for the Fruitland coal in the San Juan basin are c_p= $(233\text{-}969)x10^{-6}$ psi^{-1}. [5,24]

Coal density. Bulk density of the coal samples ranged between 1.292 g/cc and 1.389 g/cc, with an average value of 1.332 g/cc, from LCB coal samples taken at approximately 6,200-ft depth in an APC well in east-central Texas.[14] A triangular distribution of these coal density data with a most likely value of 1.332 g/cc was used in reservoir simulation.

Isotherms parameters. CH_4, CO_2, and N_2 Langmuir volume and pressure parameters for the 6,200-ft depth coal seam scenario are 363.6 scf/ton and 608.5 psia for CH_4, 961.9 scf/ton and 697.5 psia for CO_2, and 166.1 scf/ton and 2060.7 psia for N_2.[15] Synthetic isotherm for coals at approximately 4,000-ft depth were estimated to be 458.5 scf/ton and 1884.0 psia for CH_4, 1375.5 scf/ton and 1884.0 psia for CO_2, and 301 scf/ton and 6764 psia for N_2 (as received basis).

Diffusion time. Diffusion time controls the mass transfer rate from matrix (coal) to fracture (cleats). Gas phase diffusion times considered were 0, 1, and 4 days based on published values. Sorption times reported for Fort Union coals[3] in the Powder River basin (subbituminous C), Upper Medicine River coals[27] in the Western Canada Sedimentary basin (hvB bituminous), and Pottsville coals in the Black Warrior basin[4] (hvA bituminous) are 42.6-50.7 hours, 4.93 hours, and 5.8 days, respectively. For Texas low-rank coals of interest, 4 days was selected as a reasonable upper bound on diffusion/desorption time. A triangular distribution of these gas phase diffusion times, with a most likely value of 1.0 day, is used in reservoir simulation.

Reservoir pressure and temperature. At a depth of 6,200 ft in the APCL2 cooperative well, I estimate that reservoir temperature is 170°F and pressure is 2,680 psia, assuming a freshwater hydrostatic gradient of 0.435 psi/ft. At a depth of 4,000-ft, I estimate that reservoir temperature is 140°F and pressure is 1,730 psia.

Gas content. At reservoir pressure, gas content is estimated to be 295 scf/ton and 220 scf/ton for the 6,200-ft and 4,000-ft depth coal seam scenarios, respectively.

Relative permeability. In naturally fractured reservoirs, straight-line curves are typically used. However, published data for relative permeability relationships for coal reservoirs have been found to be useful for matching actual production in a variety of coal basins.[3] Fig. 4.1 shows the gas-water relative permeability curves based upon the relationship published by Gash[28,29] for coal in the Fruitland formation, San Juan basin. Capillary pressure is assumed to be zero.

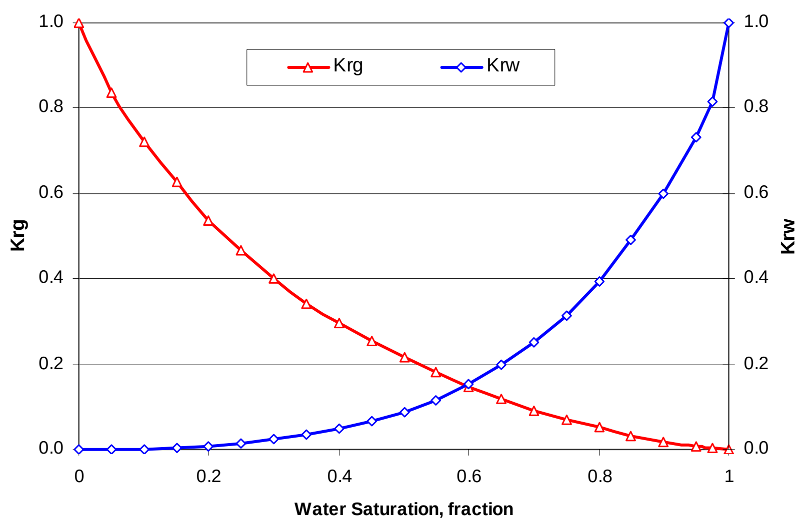


Fig. 4.1 Relative permeability curves used in simulation studies.

Operation constraints. Operating conditions for the producer wells in the model are controlled, primarily, by minimum constant bottom hole flowing pressure of 40 psia, and secondarily, by maximum gas production rate of 3,530 Mcf/D, for both base case scenarios. For the injector wells, maximum bottom hole injection pressure of 2,175 psia and maximum gas injection rate of 3,530 Mcf/D are used for the 4,000-ft depth scenario, and maximum bottom hole injection pressure of 3,625 psia and maximum gas injection rate of 3,530 Mcf/D are used for the 6,200-ft depth scenario.

4.3. Pattern Reservoir Grid Model

A reservoir simulation model that is one-eighth of a 5-spot pattern (Fig. 4.2) was built to run both deterministic and probabilistic simulations using the GEM compositional reservoir simulator developed by Computer Modeling Group (CMG) Ltd. The predicted volumes of CO_2 sequestered and CH_4 produced are scaled to a full pattern in this thesis.

A grid sensitivity study was performed by redefining the single-layer grid model from 11x11x1 to 20x20x1 grid cells in a 5-spot pattern with 40-acre well spacing. Comparison of saturation and pressure distributions, recovery efficiency, and production and injection performances of wells indicated no negative impacts resulting from use of the coarser grid model, allowing us to use it with confidence.[30] Results for these two cases are shown in Fig. 4.3. Differences in cumulative CO_2 injection and CH_4 production are about 1.5%, indicating adequacy of the coarser grid. The computer time is reduced by a factor of 6 when using the coarser-grid model.

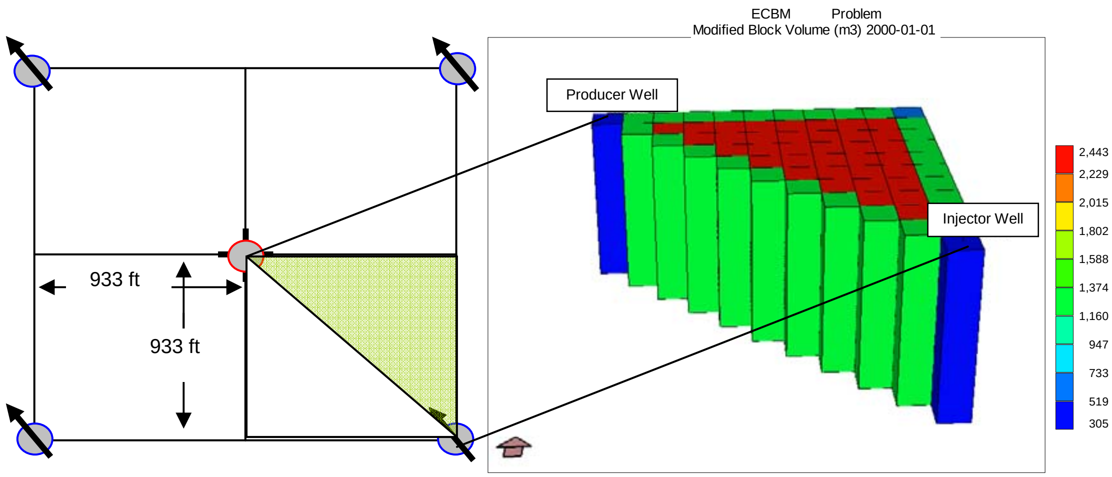


Fig. 4.2 Cartesian, orthogonal grid model of a 1/8 5-spot pattern, 40-acre well spacing.

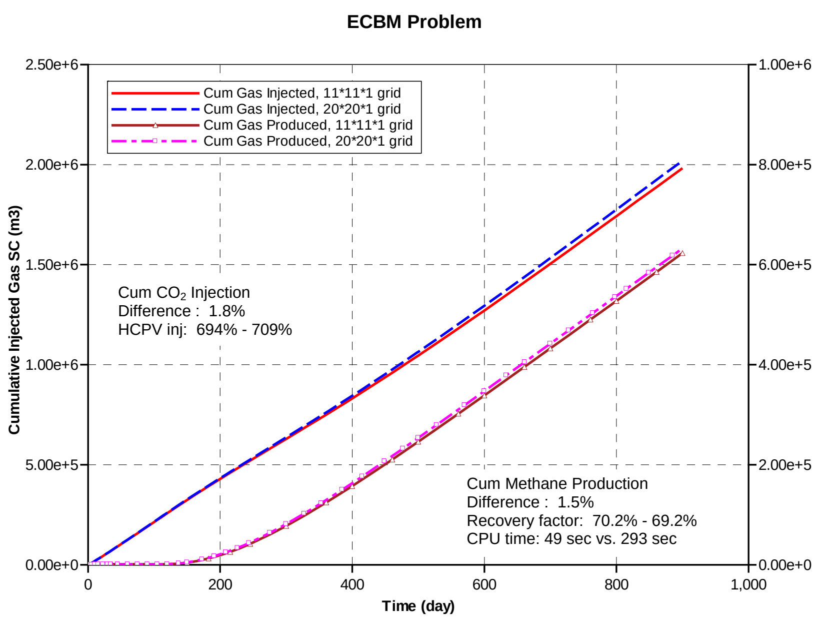


Fig. 4.3 Grid sensitivity comparison results for cumulative CO_2 injection and CH_4 production profiles, two grid sizes at 900 days of simulation time.

CHAPTER V

RESERVOIR SIMULATION OF CO_2 SEQUESTRATION AND ENHANCED COALBED METHANE PRODUCTION

To predict CO_2 sequestration and ECBM production in the Wilcox Group Lower Calvert Bluff (LCB) coalbeds, I conducted six separate simulation investigations, or cases. These cases are (1) CO_2 sequestration base case scenarios for 4,000-ft and 6,200-ft depth coalbeds in the Lower Calvert Bluff Formation of east-central Texas, (2) sensitivity study of the effects of well spacing on sequestration, (3) sensitivity study of the effects of injection gas composition, (4) sensitivity study of the effects of injection rate, (5) sensitivity study of the effects of coal dewatering prior to CO_2 injection/sequestration, and (6) sensitivity study of the effects of permeability anisotropy. On the basis of the probabilistic simulation results, I quantified uncertainty in the potential volumes of CO_2 that may be sequestered in, and CH_4 that can be produced from, the Wilcox Group low-rank coals in east-central Texas.

5.1. Reservoir Simulation Studies

5.1.1. CO_2 Sequestration/ECBM Production Base Case Scenarios

To assess reservoir performance during CO_2 sequestration in LCB coals, I conducted probabilistic simulations (1,000 iterations), modeling simultaneous injection of 100% CO_2 and production of CH_4 under the base case operating conditions, in an 80-acre 5-spot pattern (40-acre well spacing). The results of the modeling studies for the 4,000-ft (Case 1a) and 6,200-ft depth (Case 1b) base case coal seam scenarios are shown in Figs. 5.1 - 5.6.

The reservoir volume swept by CO_2 is relatively high for this single-layer model. Most of the water in the fracture system and the CH_4 in both the coal matrix and fracture system are produced. Methane recovery factors are 77.4% and 69.9% for the 4,000-ft and 6,200-ft scenarios, respectively, using the most likely values of reservoir parameters in deterministic simulations. Figs. 5.1 and 5.3 show colorfill maps of various reservoir properties at breakthrough, i.e., the time at which CO_2 comprises 5% mole fraction of the produced gas. Figs. 5.2 and 5.4 show production and injection rates and pressure profiles.

The probabilistic simulation results indicate that variability in coal properties (isotherm data, gas content, coal density, gas diffusion time) and reservoir parameters (reservoir pressure, fracture permeability) contribute significantly to uncertainties in potential performance of CO_2 injection in LCB coalbeds in east-central Texas. Fig. 5.5 shows cumulative distribution functions for CO_2 sequestered, CH_4 produced, water produced, and breakthrough times.

For the base case scenario of 4,000-ft depth (Case 1a), simulation results of 100% CO_2 injection in an 80-acre 5-spot pattern indicate that these coals with average net thickness of 20 ft can store 1.12 to 1.98 Bcf of CO_2 with an ECBM recovery of 0.39 to 0.69 Bcf, water produced of 54 to 95 Mstb, and CO_2 breakthrough time of 1,640 to 4,020 days. All ranges of results presented here and throughout this thesis represent 80% confidence intervals (P_{10} to P_{90}).

For the base case scenario of 6,200-ft depth (Case 1b), probabilistic simulation results of 100% CO_2 injection in an 80-acre 5-spot pattern indicate that these coals with average net thickness of 20 ft can store 1.27 to 2.25 Bcf of CO_2 with an ECBM recovery of 0.48 to 0.85 Bcf, water produced of 54 to 94 Mstb, and CO_2 breakthrough time of 970 to 2,430 days.

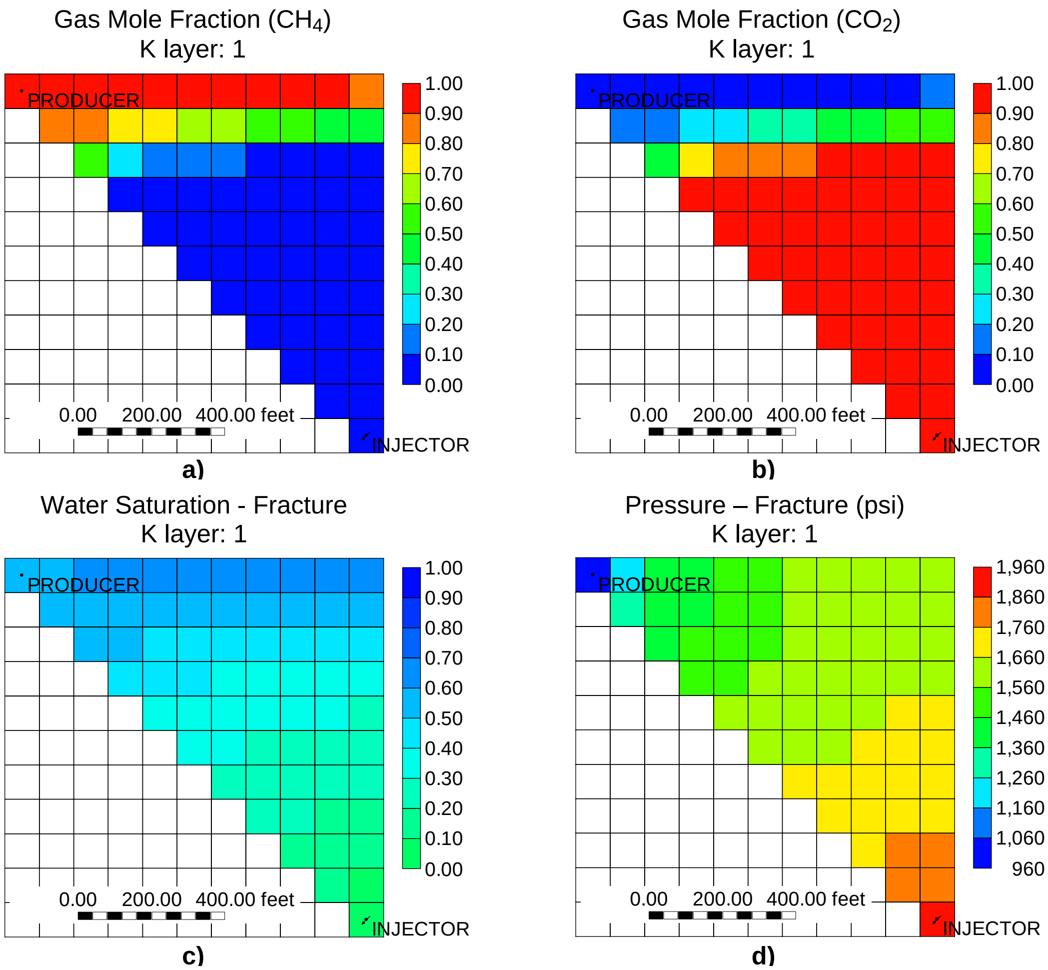
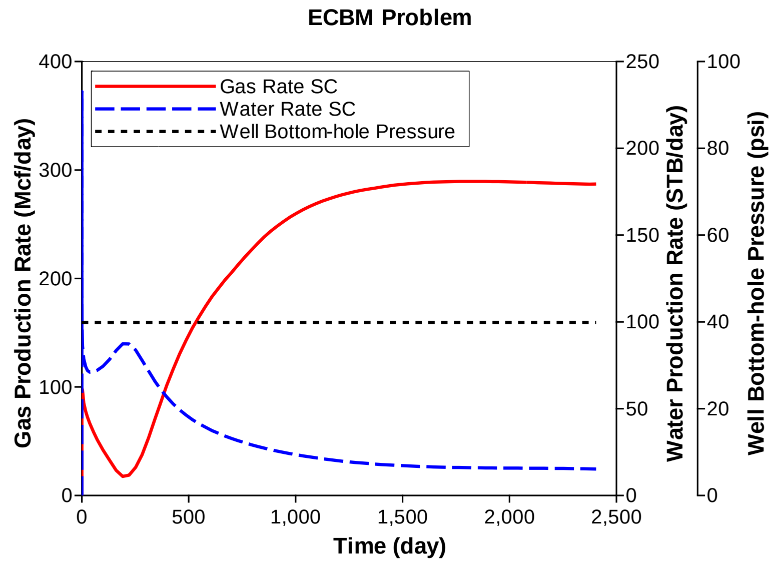
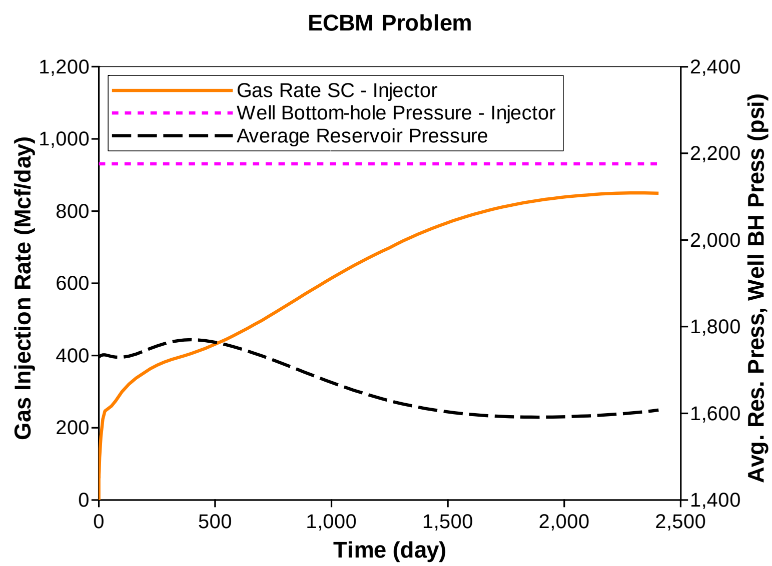


Fig. 5.1 a) Methane gas mole fraction, b) CO_2 gas mole fraction, c) water saturation in the fracture system, and d) reservoir pressure at breakthrough time of 2,405 days for the 4,000-ft depth base case coal seam scenario in the Wilcox Group, Case 1a.



a)



b)

Fig. 5.2 a) Production and b) injection profiles for gas rate, water rate, bottom hole pressure, and average reservoir pressure for the 4,000-ft depth base case, Case 1a. Rates are for an 80-acre 5-spot pattern (40-acre well spacing).

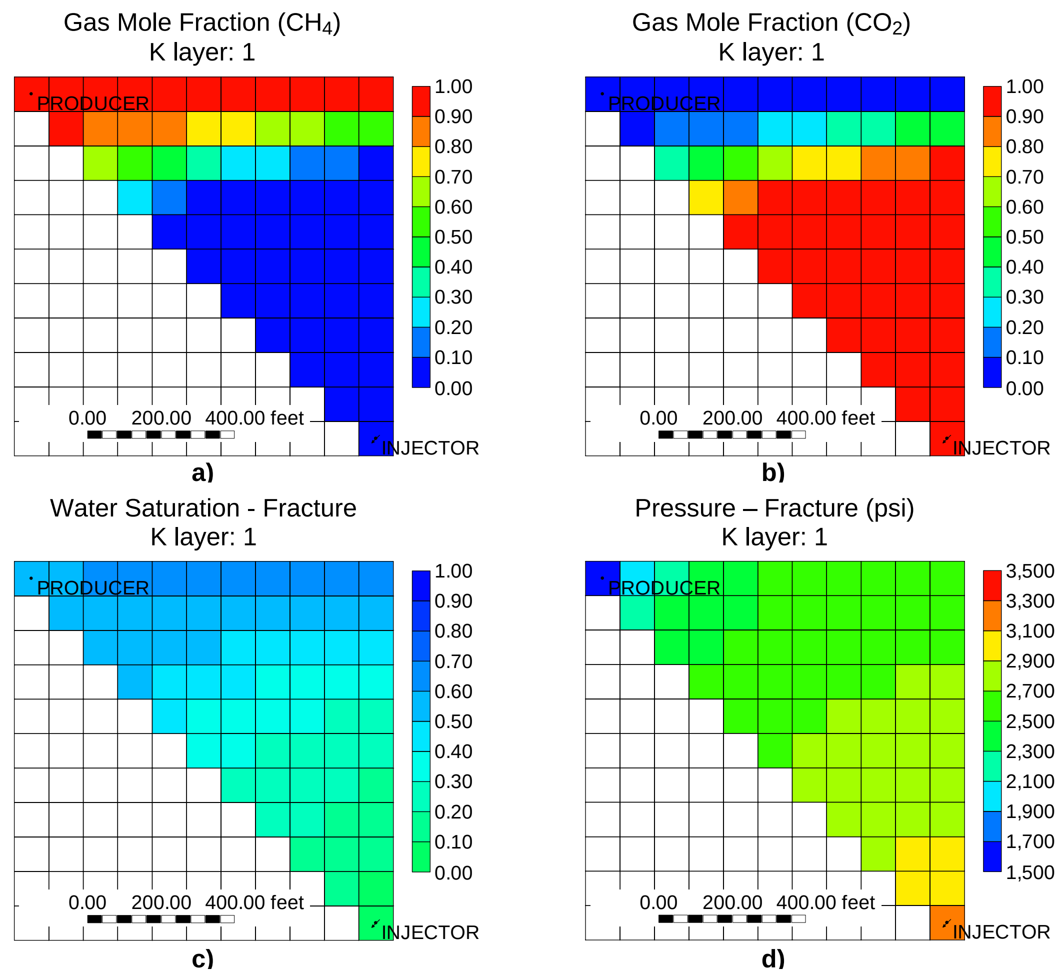


Fig. 5.3 a) Methane gas mole fraction, b) CO_2 gas mole fraction, c) water saturation in the fracture system, and d) reservoir pressure at breakthrough time of 1,461 days for the 6,200-ft depth base case coal seam scenario in the Wilcox Group, Case 1b.

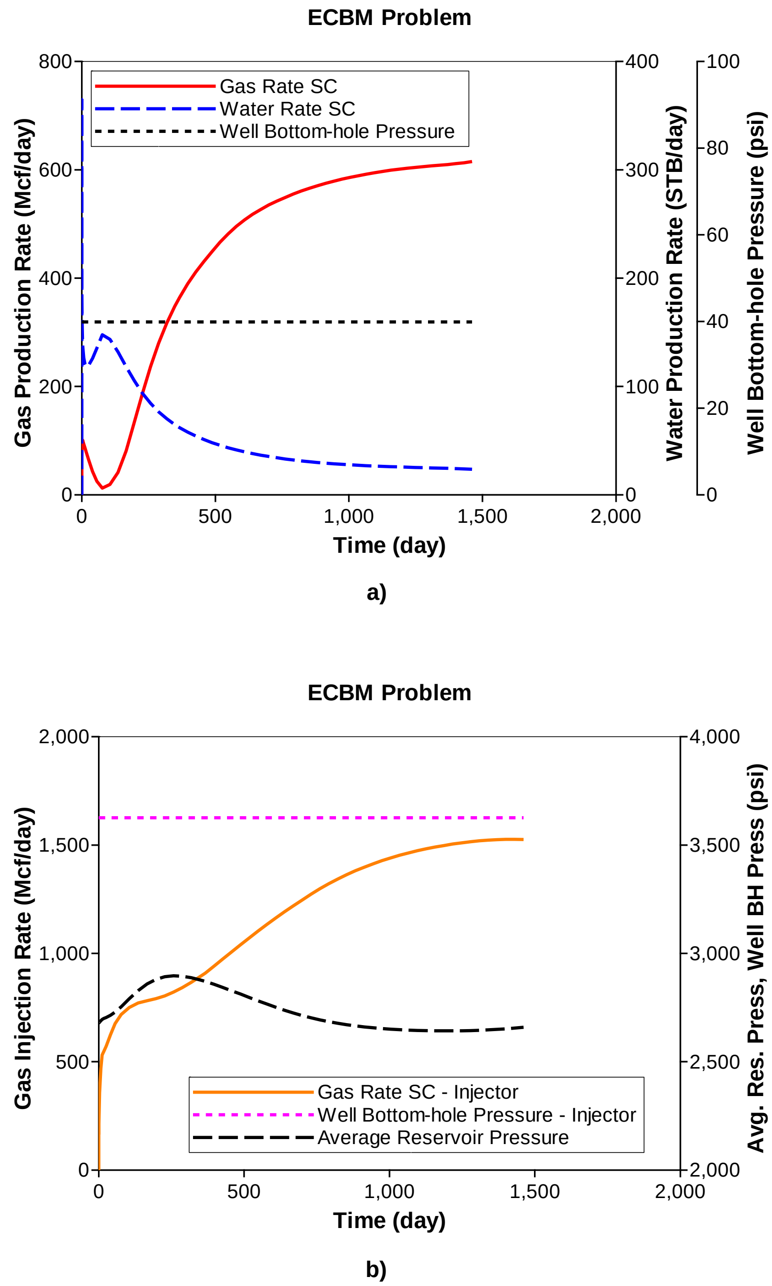


Fig. 5.4 a) Production and b) injection profiles for gas rate, water rate, bottom hole pressure, and average reservoir pressure for the 6,200-ft depth base case, Case 1b. Rates are for an 80-acre 5-spot pattern (40-acre well spacing).

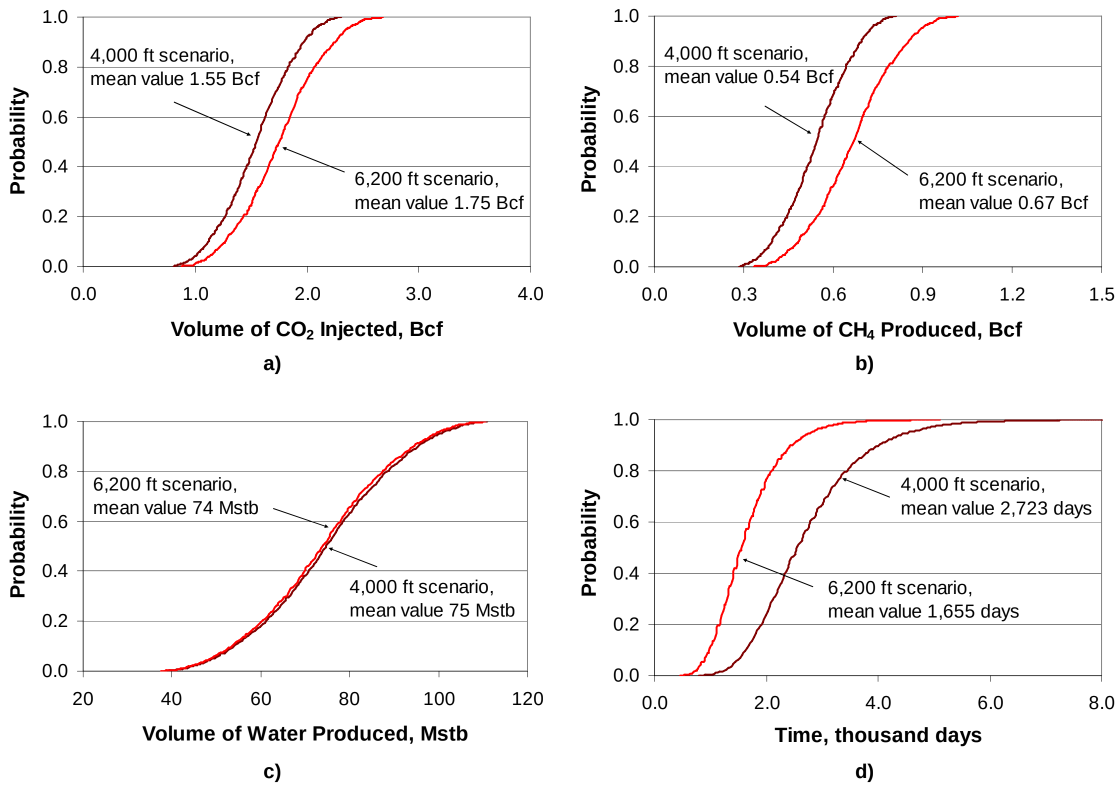


Fig. 5.5 Cumulative distribution functions for a) CO_2 injected, b) CH_4 produced, c) water produced, and d) breakthrough time in the 4,000-ft and 6,200-ft depth base case scenarios.

Fig. 5.6 shows cumulative distribution functions for methane recovery and CO_2 injection factors. CO_2 injection factor is defined as the percentage of the theoretical coal sequestration capacity injected. Simulation results of 100% CO_2 injection in an 80-acre 5-spot pattern indicates that mean values of methane recovery and CO_2 injection factors are 77.4% and 73.5%, respectively, at depths of 4,000 ft (Case 1a). Recovery and injection factors are estimated to average 69.7% and 71.5%, respectively, at depths of 6,200 ft (Case 1b).

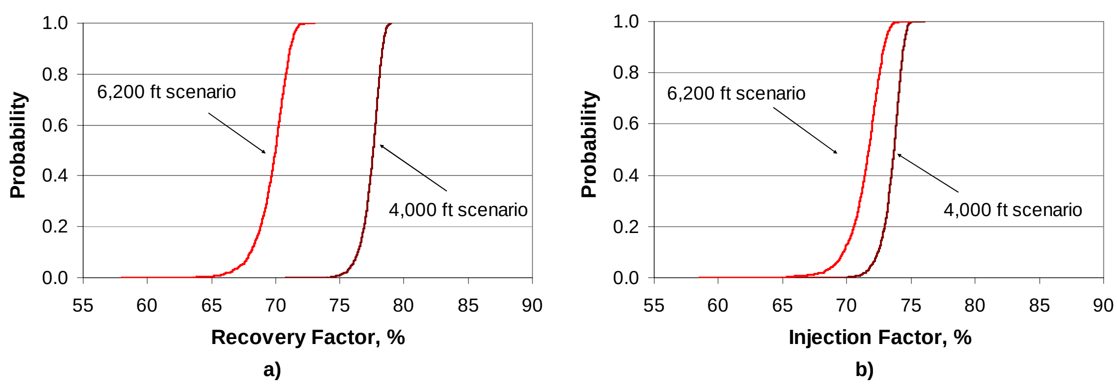


Fig. 5.6 Cumulative distributions functions for a) gas recovery factor and b) gas injection factor, for the 4,000-ft and 6,200-ft depth base case scenarios.

5.1.2. Sensitivity Study of the Effects of Well Spacing

To determine the effects of well spacing on performance of coalbed reservoirs during CO_2 sequestration and ECMB production, I conducted probabilistic simulation modeling studies (1,000 iterations) of 100% CO_2 gas injection under the base case operating conditions for 80, 160, and 240-acre well spacings for the 6,200-ft depth base case. These simulation studies are denoted as Cases 2a, 2b, and 2c, respectively. Case 1b reported results of the 40-ac well spacing case.

Fig. 5.7 shows the cumulative distribution functions for the volumes of CO_2 sequestered, CH_4 produced, water produced, and breakthrough times, respectively, for Cases 1b, 2a, 2b, and 2c. Mean values of the estimated volumes of CO_2 that can be sequestered in LCB coals are 1.75, 3.59, 7.25, and 10.94 Bcf for 40, 80, 160, and 240-acre well spacings in a 5-spot injection pattern. Corresponding CH_4 production values are 0.67, 1.36, 2.76, and 4.16 Bcf, at breakthrough times of 1,655, 3,443, 7154, and 10,967 days, respectively. CH_4 recovery factors range from 69.9% to 72.7% for cases 1b to 2c using the most likely values of reservoir parameters in deterministic simulations.

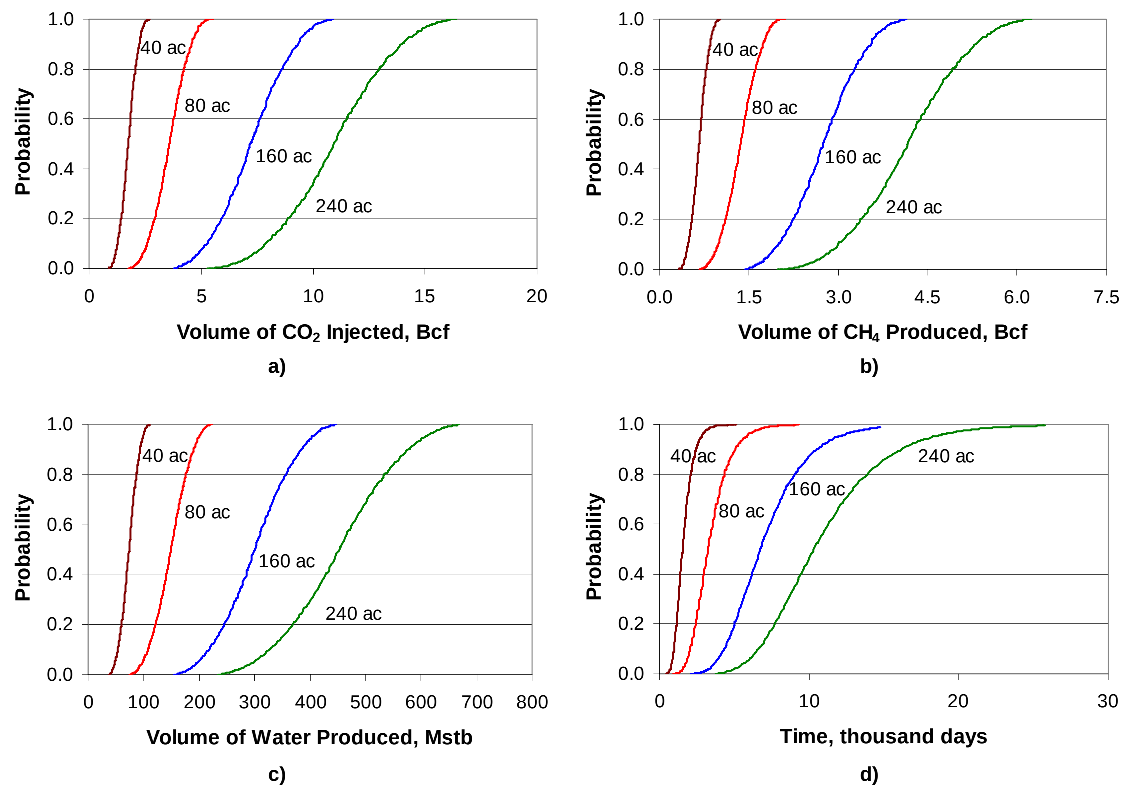


Fig. 5.7 Cumulative distribution functions for a) CO_2 injection, b) CH_4 production, c) water production, and d) breakthrough time, 6,200-ft depth coal reservoir scenario, for 40, 80, 160, and 240-ac well spacings in a 5-spot pattern.

Fig. 5.8 show the cumulative distribution functions for the volumes of CO_2 sequestered, CH_4 produced, and water produced normalized to a 40-acre well spacing (80-acre pattern area) basis. For the 6,200-ft depth base case scenario, the mean values of estimated volumes of CO_2 that can be sequestered in LCB coals are 1.75, 1.79, 1.81, and 1.82 Bcf per 80 acres for 40, 80, 160, and 240-acre well spacing, respectively, in a 5-spot injection pattern. Corresponding normalized CH_4 production values are 0.67, 0.68, 0.69, and 0.69 Bcf per 80 acres. Thus, total injected and produced volumes increase slightly with increasing well spacing, even though average production and injection rates increase with smaller well spacings. However, the sensitivity to well spacing of CO_2 volumes sequestered and methane volumes produced on a unit-area basis is not great.

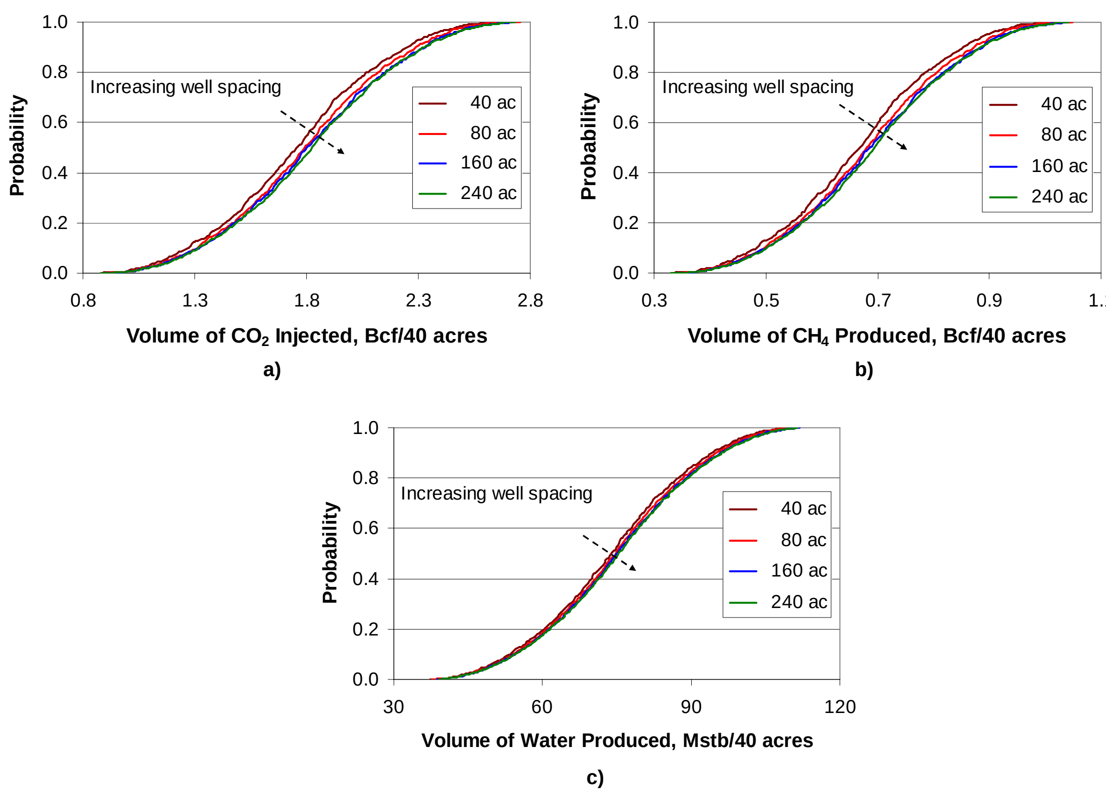


Fig. 5.8 Cumulative distribution functions for a) CO_2 injection, b) CH_4 production, and c) water production, 6,200-ft depth reservoir scenario, for 40, 80, 160, and 240-ac well spacing in a 5-spot pattern, normalized to a 40-acre well spacing (80-acre pattern area) basis.

5.1.3. Sensitivity Study of the Effects of Injection Gas Composition

To determine the effects of injection gas composition on performance of CO_2 sequestration and ECMB production in Wilcox coals in east-central Texas, I conducted probabilistic simulations, each consisting of 1,000 iterations, modeling injection of 50% CO_2-50% N_2 (Case 3a) and flue gas (13% CO_2-87% N_2, Case 3b) under the base case operating conditions, in an 80-acre 5-spot pattern (40-acre well spacing) for the 6,200-ft depth case. Modeling of 100% CO_2 injection under these same conditions was presented previously as Case 1b. The results of the modeling studies for the 6,200-ft depth coal seam scenario with variable injection gas composition are shown in Figs. 5.9 – 5.13.

The reservoir volumes swept by CO_2 and/or N_2 are relatively high for this single-layer model. Mole percents of methane recovered are 69.5%, 90.2%, and 98.2% for Cases 1b, 3a, and 3b, respectively, for the 6,200-ft depth scenario using the most likely values of reservoir parameters in deterministic simulations. These high recovery efficiencies result from using a termination criterion of 5% CO_2 mole fraction in the produced gas (CO_2 breakthrough) and no cutoff based on N_2 content. This termination criterion does not necessarily represent an economic limit. Most of the water in the fracture system and the CH_4 in both the coal matrix and fracture system are produced in these cases. Figs. 5.9 and 5.10 show colorfill maps of various reservoir properties at breakthrough.

Fig. 5.11 shows methane, CO_2, and N_2 gas mole production rates for Cases 1b, 3a and 3b, respectively, using the most likely values of reservoir parameters in deterministic simulations. Mole rates are for an 80-acre 5-spot pattern (40-acre well spacing). In Cases 3a and 3b, N_2 breaks through at the production well relatively early and, by the time CO_2 breaks through, the N_2 gas mole production rate exceeds the methane rate. These results are consistent with field tests and previous simulation results.[1,31] Fig. 5.12 shows the corresponding cumulative total gas production and injection profiles.

Fig. 5.13 shows cumulative distribution functions for CO_2 sequestered, CH_4 produced, water produced, and breakthrough times for Cases 1b, 3a, and 3b. The probabilistic simulation results indicate that injection gas composition has a significant impact on performance of CO_2/N_2 injection in LCB coal beds in east-central Texas. Simulation results of 50% CO_2-50% N_2 injection (Case 3a) indicate that these coals can store 0.86 to 1.52 Bcf of CO_2 at depths of 6,200 ft with an ECBM recovery of 0.62 to 1.10 Bcf, water produced of 60 to 106 Mstb, and CO_2 breakthrough time of 1,670 to 4,080 days. Simulation results of 13% CO_2-87% N_2 injection (Case 3b, typical flue gas composition) indicate that these same coals can store 0.34 to 0.59 Bcf of CO_2 at depths of 6,200 ft, with an ECBM recovery of 0.68 to 1.20 Bcf, water produced of 66 to 117 Mstb, and CO_2 breakthrough time of 2,620 to 6,240 days. Results are for an 80-acre 5-spot pattern (40-acre well spacing). All ranges represent 80% confidence intervals (P_{10} to P_{90}).

These results indicate that CO_2 sequestration and ECMB production with injection gas compositions ranging from typical flue gas (13% CO_2-87% N_2) to 100% CO_2 are technically feasible in east-central Texas LCB coals. The results also indicate that increasing N_2 content in the injection gas results in improved methane production performance, which is consistent with other published results.[31,32]

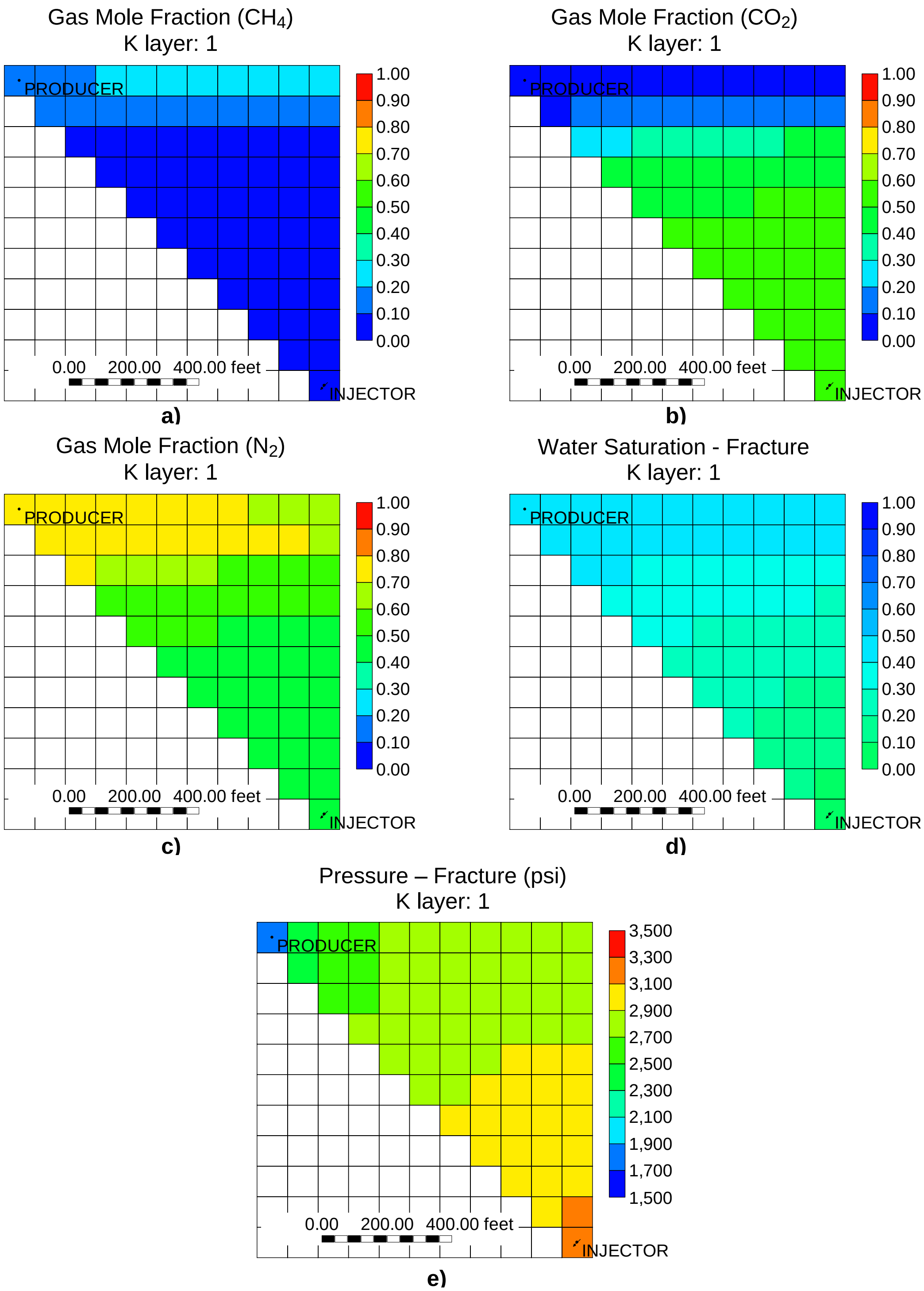


Fig. 5.9 a) Methane gas mole fraction, b) CO_2 gas mole fraction, c) N_2 gas mole fraction, d) water saturation in the fracture system, and e) reservoir pressure at breakthrough time of 2,435 days for the 6,200-ft depth reservoir scenario, Case 3a (50% CO_2 – 50% N_2 injection).

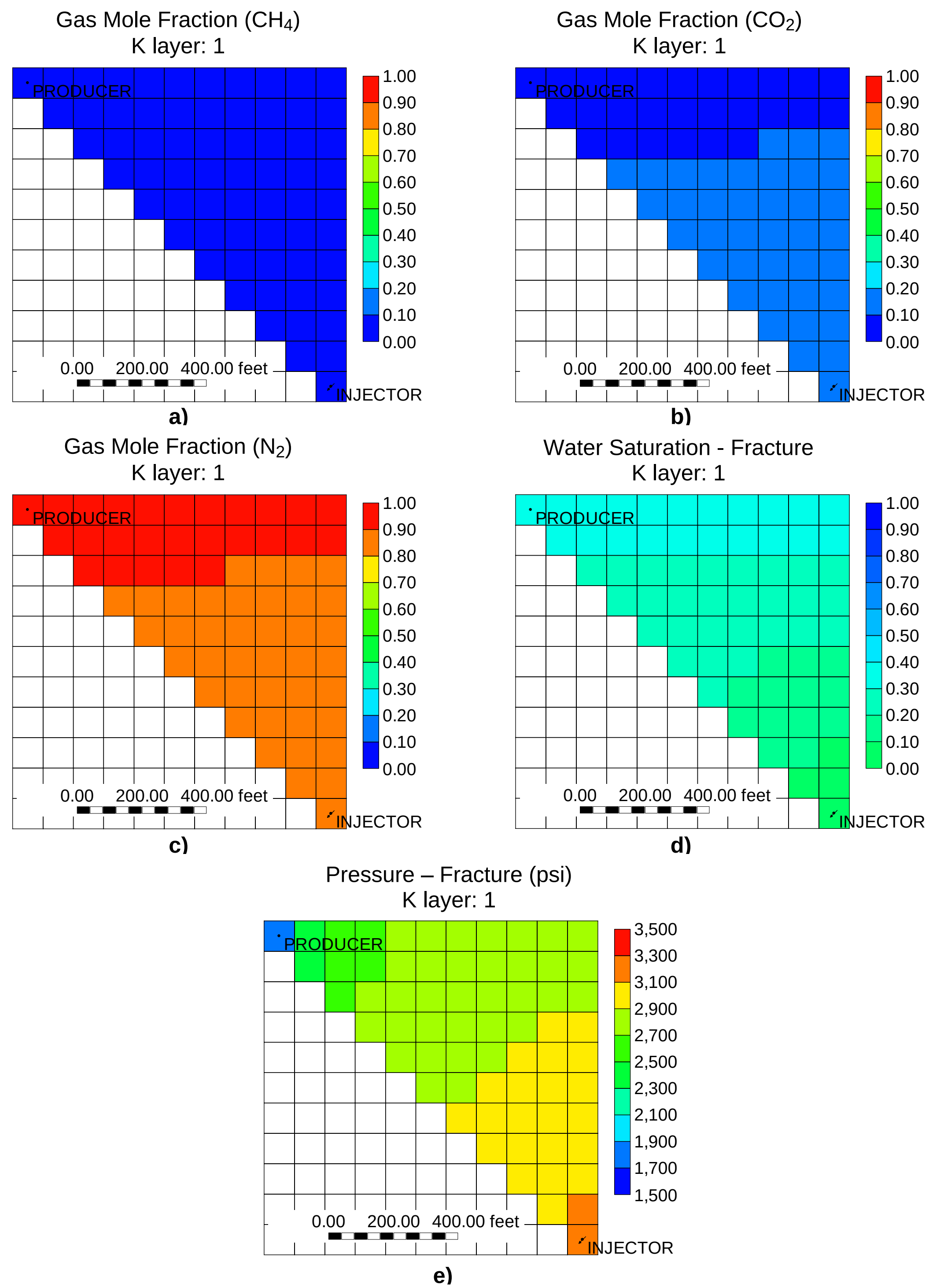


Fig. 5.10 a) Methane gas mole fraction, b) CO_2 gas mole fraction, c) N_2 gas mole fraction, d) water saturation in the fracture system, and e) reservoir pressure at breakthrough time of 3,775 days for the 6,200-ft depth reservoir scenario, Case 3b (13% CO_2 – 87% N_2 injection).

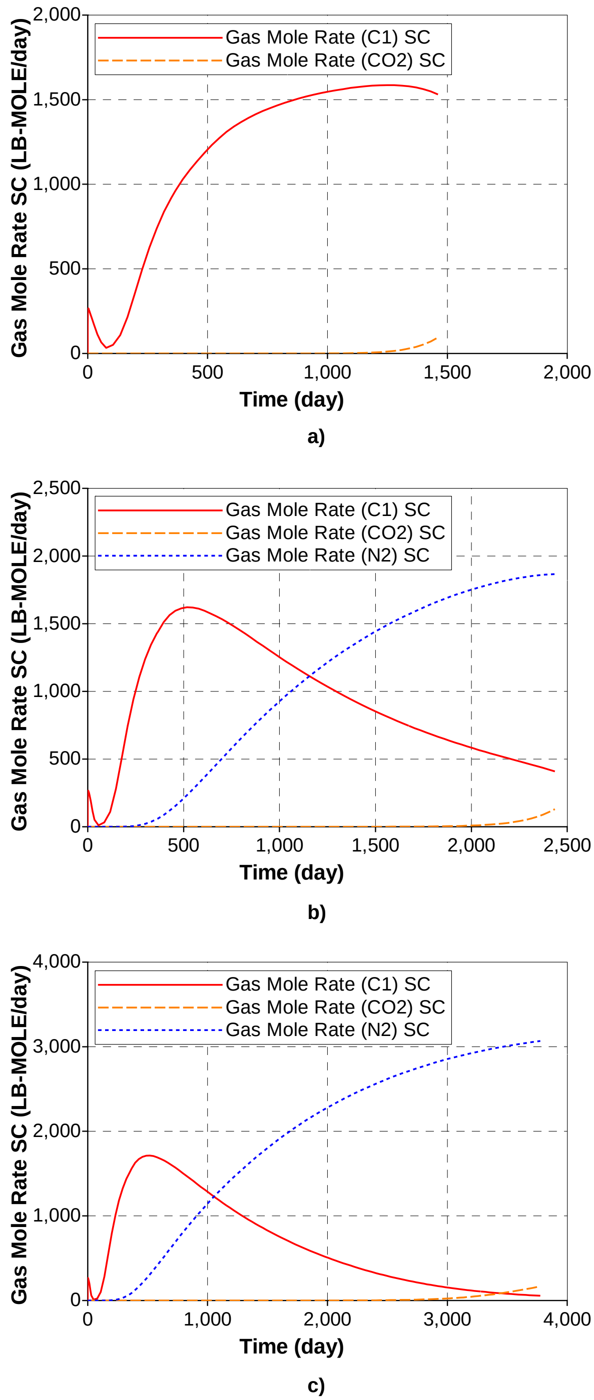


Fig. 5.11 Methane, CO_2, and N_2 gas mole production rates for the 6,200-ft depth reservoir scenario. a) Case 1b (100% CO_2 injection), b) Case 3a (50% CO_2 – 50% N_2 injection), and c) Case 3b (13% CO_2 – 87% N_2 injection). Mole rates are for an 80-acre 5-spot pattern (40-acre well spacing).

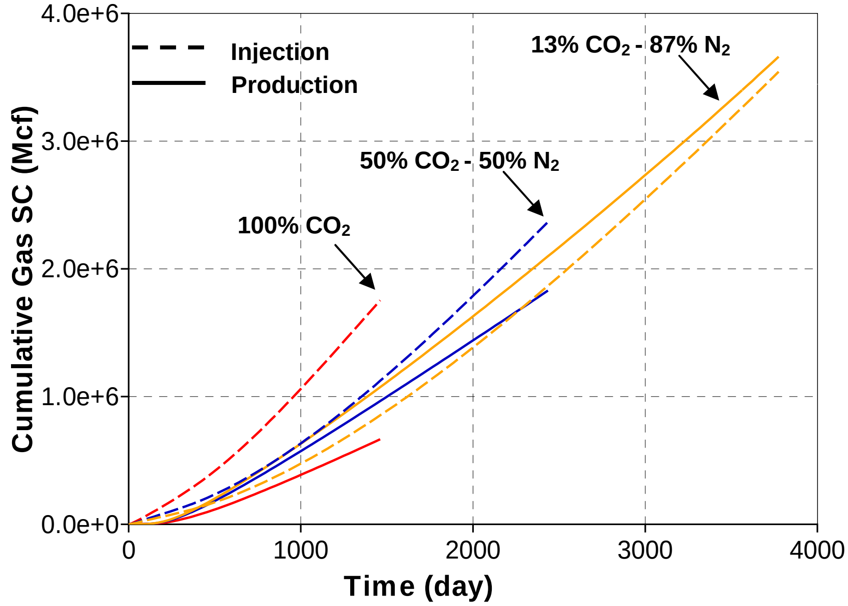


Fig. 5.12 Cumulative gas production and injection for the 6,200-ft depth reservoir scenario. Case 1b (100% CO_2 injection), Case 3a (50% CO_2 – 50% N_2 injection), Case 3b (13% CO_2 – 87% N_2 injection). Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

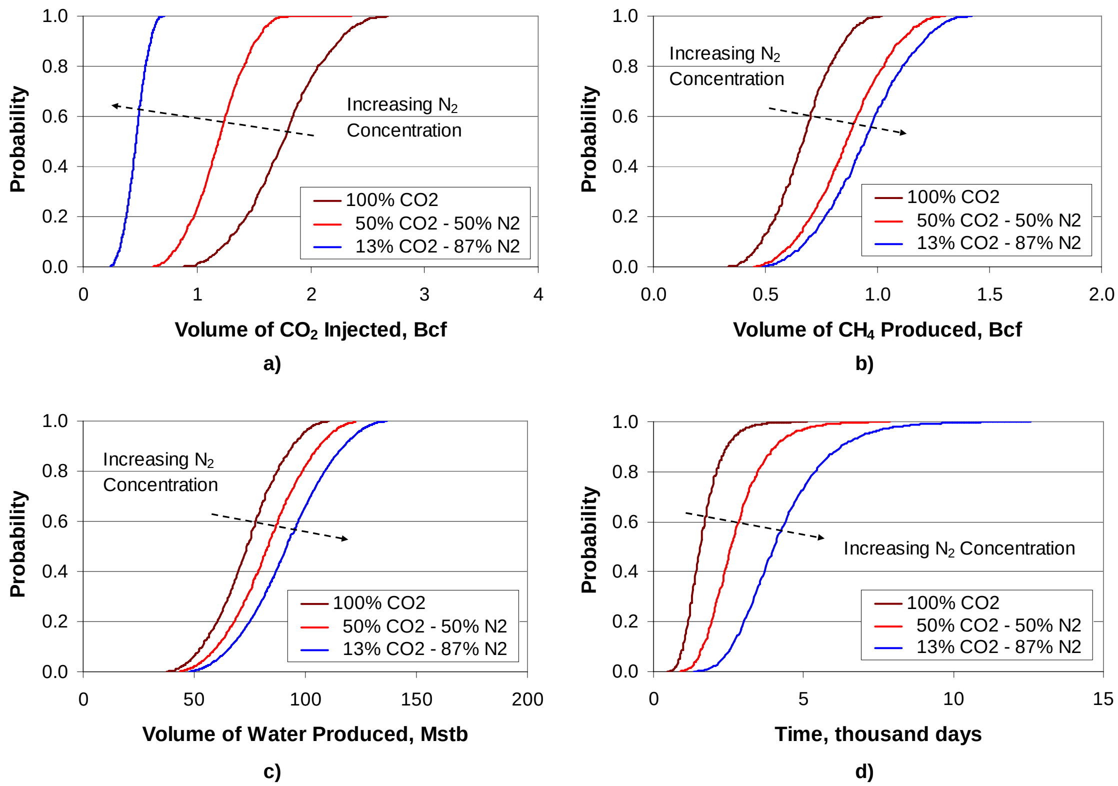


Fig. 5.13 Cumulative distribution functions for a) CO_2 injected, b) CH_4 produced, c) water produced, and d) breakthrough time, per 80-acre 5-spot pattern in the 6,200-ft depth reservoir scenarios, Cases 1b, 3a, and 3b.

5.1.4. Sensitivity Study of the Effects of Injection Rate

To determine the effects of injection rate on performance of CO_2 sequestration and ECMB production in Wilcox coals in east-central Texas, I conducted deterministic simulation modeling studies of 100% CO_2 gas injection for the 6,200-ft depth base case (Case 1b) under two sets of operating conditions, base case operating conditions and conditions in which the pressure drop between injector and producer is reduced by 920 psi (Table 4.3).

Case 1b was for the 40-ac well spacing case with the production well constrained at a constant bottomhole flowing pressure of 40 psia and the injection well constrained at a constant bottomhole injection pressure of 3,625 psia. A modified case with the production well constrained by a constant bottomhole flowing pressure of 500 psia and the injection well constrained by a bottomhole injection pressure of 3,165 psia was selected to model the effect of variable injection rate. Wells are secondarily constrained in the model by maximum gas production and injection rates of 3,530 Mcf/D. Figs. 5.14-5.16 show cumulative gas production and injection and average reservoir pressure vs. time for the most-likely, least-favorable, and most-favorable sets of reservoir parameters under these two sets of operating conditions.

There are no significant differences in the cumulative volumes of CH_4 produced or CO_2 injected due to the lower injection rate. The primary differences are in project lives, with longer breakthrough times as injection rates decrease. Breakthrough times for 80-acre patterns (40-acre well spacing) ranged from 670 days (1.8 years) to 750 days (2.0 years), from 1,460 days (4.0 years) to 2,070 days (5.6 years), and from 5,110 days (14.0 years) to 7,240 days (19.8 years) for the most-favorable, most-likely and least-favorable reservoir parameters, respectively, under the well operating conditions investigated.

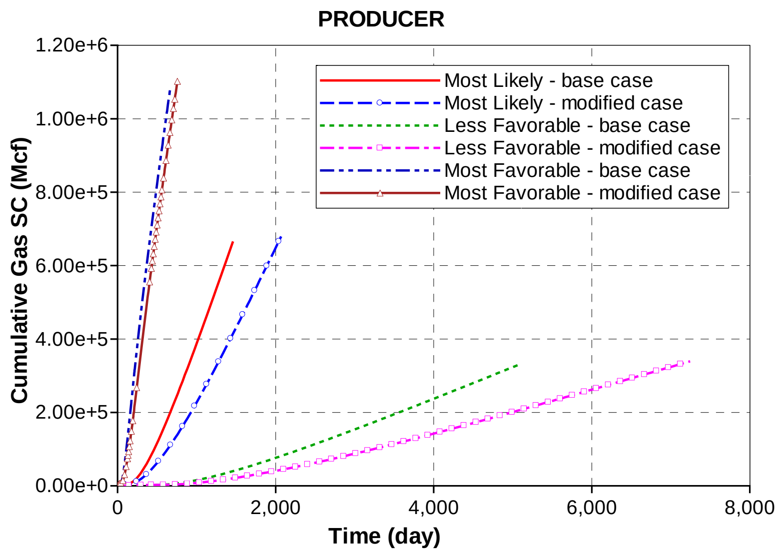


Fig. 5.14 Cumulative CH_4 production for the 6,200-ft depth reservoir scenario for the most-likely, least-favorable, and most-favorable reservoir parameters, under different well operating conditions, Case 4 (100% CO_2 injection). Modified case represents lower pressure drop between injector and producer. Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

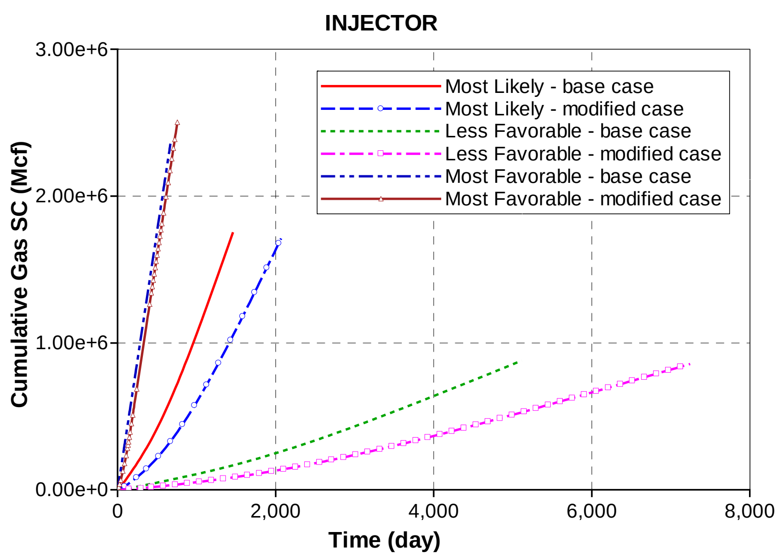


Fig. 5.15 Cumulative CO_2 injection for the 6,200-ft depth reservoir scenario for the most-likely, least-favorable, and most-favorable reservoir parameters, under different well operating conditions, Case 4 (100% CO_2 injection). Modified case represents lower pressure drop between injector and producer. Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

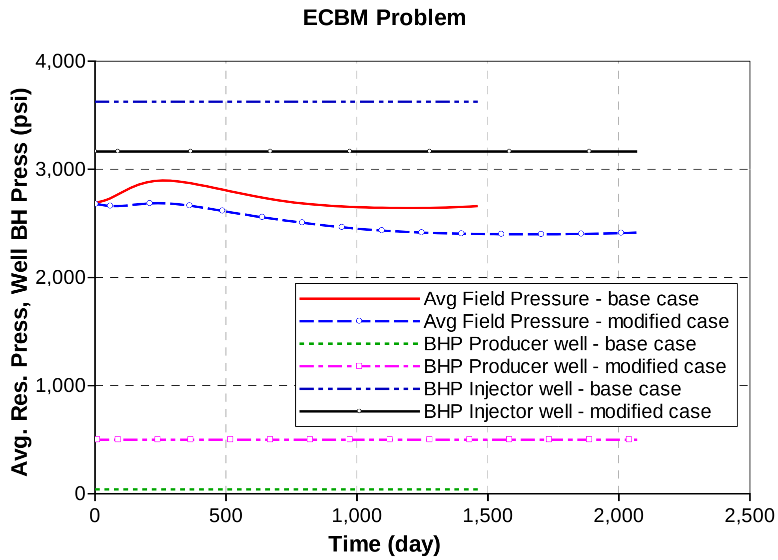


Fig. 5.16 Average field pressure and bottom hole pressure in the producer and injector wells for the 6,200-ft depth, in an 80-acre 5-spot pattern (40-acre well spacing), Case 4 (100% CO_2 injection), for the most-likely reservoir parameters. Modified case represents lower drawdown.

5.1.5. Sensitivity Study of the Effects of Coal Dewatering Prior to CO_2 Injection

To determine the effects of dewatering the coals prior to CO_2 injection on performance of CO_2 sequestration and ECMB production in Wilcox coals in east-central Texas, I conducted deterministic simulation modeling studies of 100% CO_2 injection under the base case operating conditions for two production/injection schedules for the 6,200-ft depth base case.

To compare with the case in which injection and production start simultaneously (Case 1b), I modified this case to start CO_2 injection after 6 months and after 18 months of production. I performed deterministic sensitivity analysis for the most-likely, least-favorable, and most-favorable reservoir parameters. Figs. 5.17 and 5.18 show cumulative gas production and injection for 100% CO_2 injection in the 6,200-ft depth reservoir, dewatering the coals 0, 6 and 18 months prior to CO_2 injection. Fig. 5.19 shows the CH_4 production rates, CO_2 injection rates, water production rates, and average field pressure, respectively, for the 6,200-ft depth reservoir scenario with the most-likely reservoir parameters.

The dewatering sensitivity study shows that total volumes of CO_2 sequestered and methane produced are not sensitive to the start of injection relative to the start of production. However, as time to start CO_2 injection is increased, the total time to reach CO_2 breakthrough increases. Breakthrough times for 80-acre patterns (40-acre well spacings) ranged from 850 days (2.3 years) to 5,380 days (14.7 years) for the reservoir parameters and well injection/production schedules investigated.

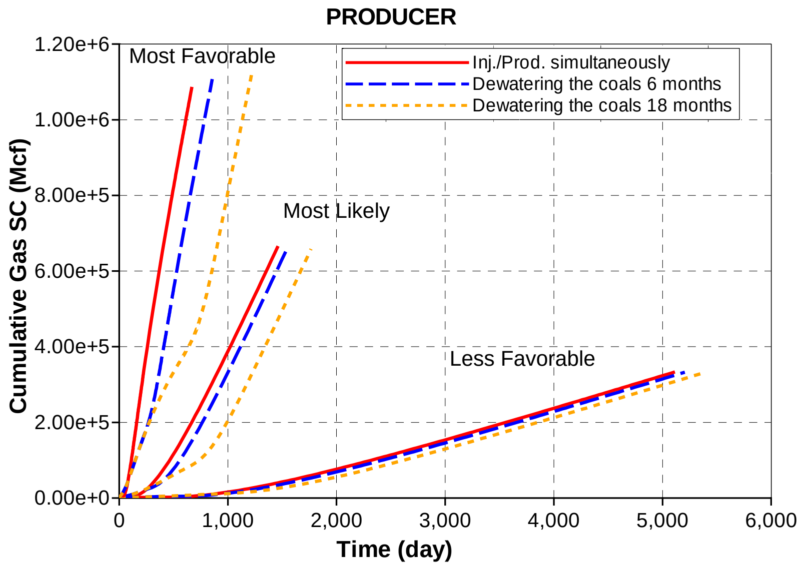


Fig. 5.17 Cumulative CH_4 production for the 6,200-ft depth reservoir scenario for the most-likely, least-favorable, and most-favorable reservoir parameters, dewatering the coals 0, 6, and 18 months, Case 5 (100% CO_2 injection). Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

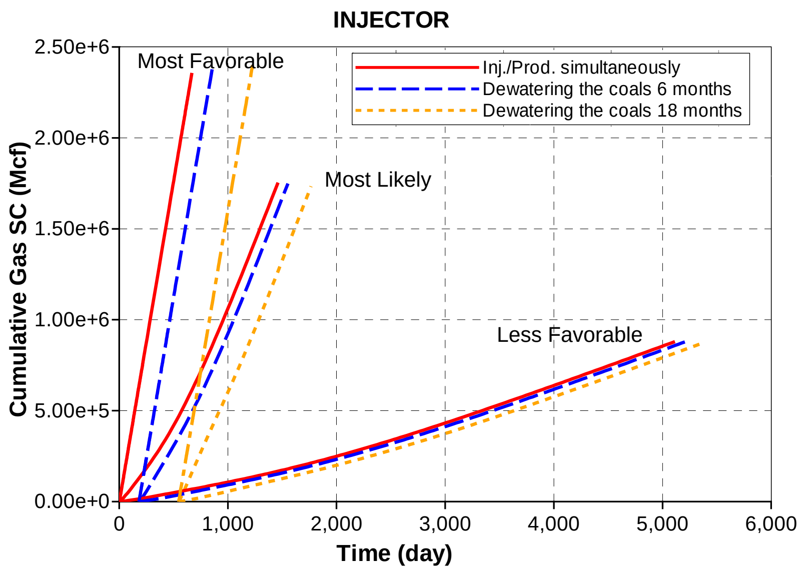


Fig. 5.18 Cumulative CO_2 injection for the 6,200-ft depth reservoir scenario for the most-likely, least-favorable, and most-favorable reservoir parameters, dewatering the coals 0, 6, and 18 months, Case 5 (100% CO_2 injection). Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

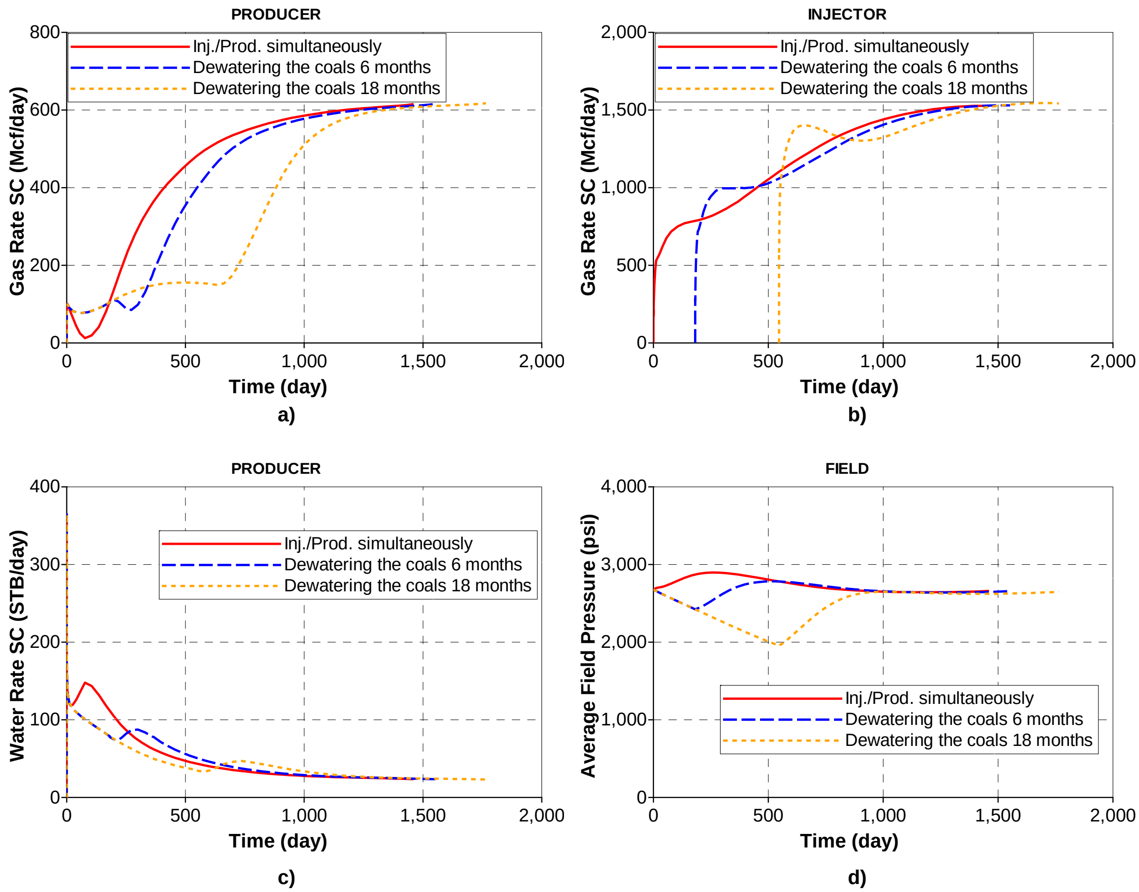


Fig. 5.19 a) CH_4 production rates, b) CO_2 injection rates, c) water production rates, and d) average field pressure for the 6,200-ft depth coal seam scenario for the most-likely reservoir parameters, dewatering the coals 0, 6, and 18 months, Case 5 (100% CO_2 injection). Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

5.1.6. Sensitivity Study of the Effects of Permeability Anisotropy

To determine the impacts of permeability anisotropy on performance of CO_2 sequestration and ECMB production in Wilcox coals in east-central Texas, I conducted deterministic simulation modeling studies of 100% CO_2 injection for the 6,200-ft depth coal seam scenario, using the most likely values of reservoir parameters, under the base case operating conditions. I used permeability aspect ratios of face cleat permeability (k_x) to butt cleat permeability (k_y) of 1:1, 2:1, 4:1 and 8:1.

Permeability anisotropy measured in a coal seam in the Bowen basin, Queensland, by a multiple interference test was 2.8:1.[33] This is considered to be a moderate degree of anisotropy, lying within the range of ratios measured in three seams at the Rock Creek site in the Warrior basin,[34] where three measurements were reported: a well-developed anisotropy ratio of 17:1, a moderate anisotropy ratio of 2.3:1, and a virtually 1:1 isotropic case. A permeability anisotropy ratio of 4:1 was obtained from type curve analysis of a four well injection interference test conducted at the Dartbrook Mine, in the Sydney coal basin, Australia.[35] Permeability anisotropy ratios from 1:1 to 8:1 are considered to be a reasonable range for this sensitivity study.

Results of the sensitivity study using a diagonal orientation in which the line connecting producer and injector wells is offset 45° with the permeability axes (Case 6a), a parallel orientation with face cleat permeability (k_x) aligned with the line connecting injector and producer wells (Case 6b), and a parallel orientation with butt cleat permeability (k_y) aligned with the injector and producer wells (Case 6c) are shown in Figs. 5.20-5.22.

Using the diagonal orientation in which the line connecting producers with injectors is offset 45° with the permeability axes (Case 6a), anisotropic permeability sensitivity studies for 100% CO_2 injection indicate that methane production and CO_2 injection rates decrease with increasing permeability aspect ratio (Fig. 5.20). There are no significant differences in the cumulative volumes of CH_4 produced or CO_2 injected due to increasing permeability anisotropy. The primary differences are in project lives, with longer breakthrough times as injection rates decrease with increasing permeability aspect ratio. Breakthrough times for 80-acre patterns (40-acre well spacing) ranged from 1460 days (4.0 years) to 1700 days (4.7 years), for the reservoir parameters and permeability aspect ratios investigated. Simulation results indicate that LCB coals can store 1.75 to 1.69 Bcf of CO_2 at depths of 6,200 ft with an ECBM recovery of 0.67 to 0.71 Bcf, water produced of 74 to 79 Mstb, at breakthrough times, for permeability anisotropy ratios increasing from 1:1 to 8:1, respectively. Methane recovery factors range between 69.9% and 74.2% at breakthrough.

Next, I simulated two parallel orientations in which the line connecting producers with injectors is aligned with (1) the face cleat permeability (k_x) axis, and (2) the butt cleat permeability (k_y) axis, respectively. Grid orientation effects contribute to an earlier breakthrough time for the isotropic case for the parallel grid as compared to the diagonal grid. This prevents a direct comparison of diagonal orientations to parallel orientations; however, the variation in performance with anisotropy ratios for the respective orientations should still be relevant.

Using the orientation with face cleat permeability (k_x) parallel with the line connecting injector and producer wells (Case 6b), cumulative volumes of CH_4 produced and CO_2 injected decrease significantly with increasing permeability anisotropy (Fig. 5.21). Gas injection and production rates increase with increasing permeability aspect ratio, causing rapid CO_2 breakthrough at the production well and hence reducing the cumulative volumes of CO_2 injected and CH_4 produced. Simulation results indicate that these coals can store only 1.37 to 0.63 Bcf of CO_2 at depths of 6,200 ft with an ECBM recovery of 0.51 to 0.23 Bcf, water produced of 67 to 46 Mstb, and CO_2 breakthrough time of 1,220 to 490 days for permeability anisotropy ratios increasing from 1:1 to 8:1, respectively.

Gas recovery factors range between 54.1% and 23.5% at breakthrough, indicative of low sweep efficiency.

Using the orientation with butt cleat permeability (k_y) parallel with the line connecting injector and producer wells (Case 6c), there are significant differences in the incremental volumes of CH_4 produced and CO_2 injected due to increasing permeability anisotropy (Fig. 5.22). Gas injection and production rates decrease with increasing permeability aspect ratio, causing longer CO_2 breakthrough times and hence increasing the cumulative volumes of CH_4 produced and CO_2 injected. Simulation results indicate that these coals can store 1.37 to 1.79 Bcf of CO_2 at depths of 6,200 ft with an ECBM recovery of 0.51 to 0.67 Bcf, water produced of 67 to 74 Mstb, and CO_2 breakthrough time of 1,220 to 2,620 days for permeability anisotropy ratios increasing from 1:1 to 8:1, respectively. Gas recovery factors range between 54.1% and 70.8% at breakthrough, indicative of improved sweep efficiency.

Based on these results for an 80-acre 5-spot pattern, permeability anisotropy can have a significant impact on carbon sequestration and ECBM projects due to the effects on injection and production rates, which will dictate CO_2 sequestration capacity and ECBM recovery. The degree and orientation of the anisotropy are influenced by regional geology, e.i., structural trends, stress direction, and fracture orientation. Recognition of the magnitude and orientation of permeability anisotropy in coal reservoirs is important for optimal design of CO_2 sequestration and ECBM projects.

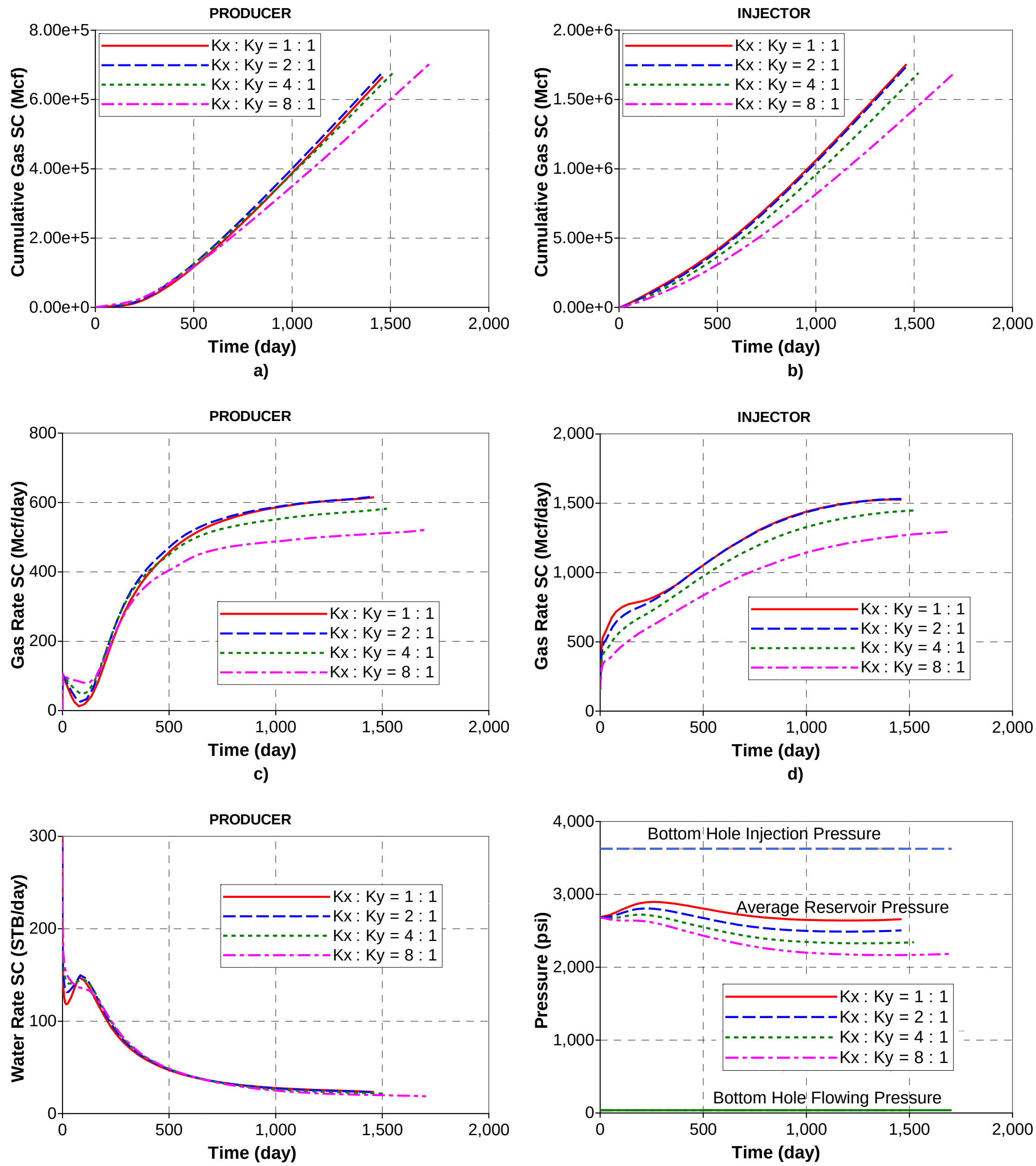


Fig. 5.20 Effect of permeability aspect ratio on a) cumulative CH_4 production, b) cumulative CO_2 injection, c) CH_4 production rates, d) CO_2 injection rates, e) water production rates, and f) average field pressure, for the 6,200-ft depth coal seam scenario and the most-likely reservoir parameters, using a diagonal orientation, Case 6a (100% CO_2 injection). Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

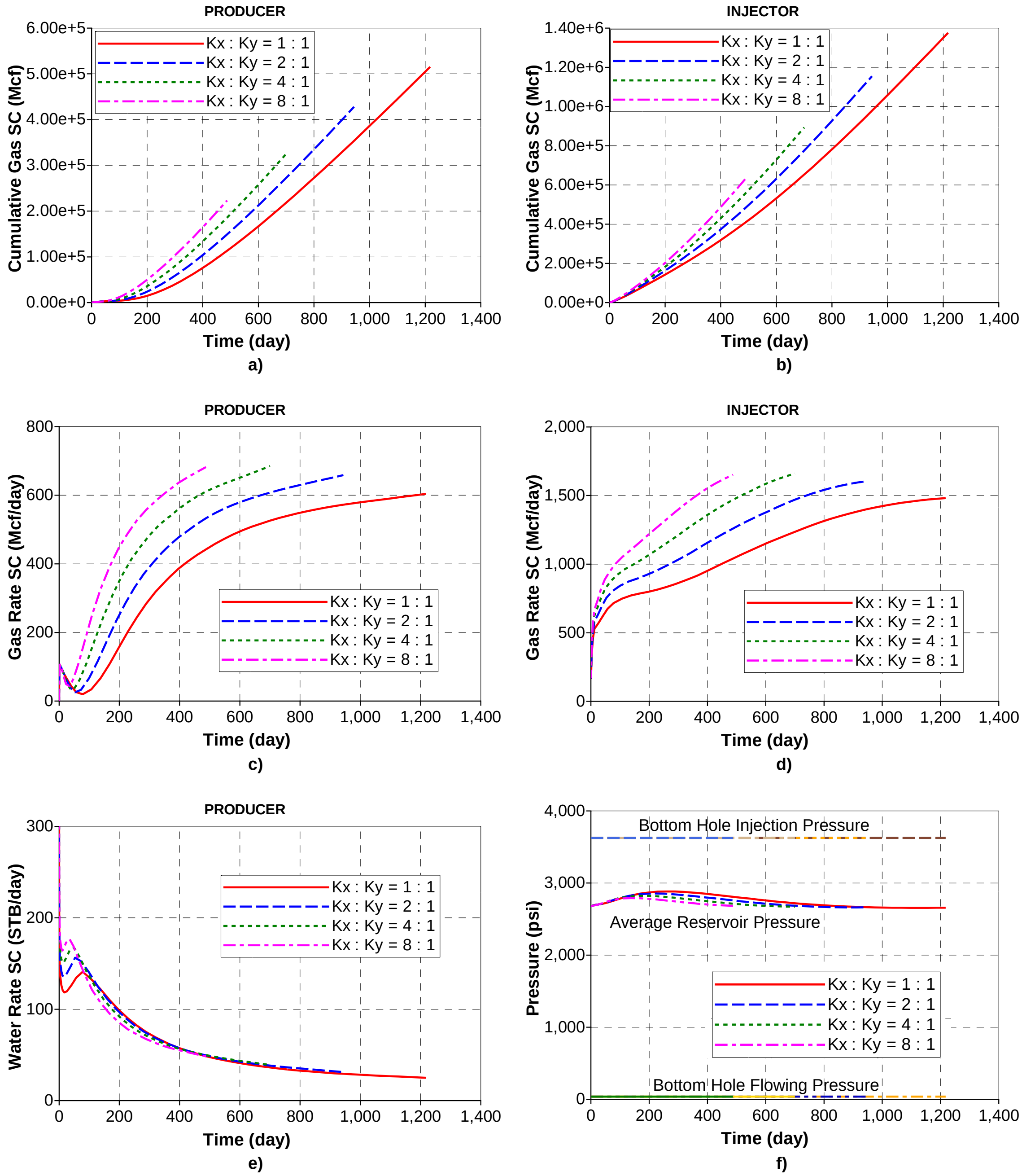


Fig. 5.21 Effect of permeability aspect ratio on a) cumulative CH_4 production, b) cumulative CO_2 injection, c) CH_4 production rates, d) CO_2 injection rates, e) water production rates, and f) average field pressure, for the 6,200-ft depth coal seam scenario and the most-likely reservoir parameters, using a parallel orientation with face cleat permeability (k_x) aligned with the injector and producer wells, Case 6b (100% CO_2 injection). Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

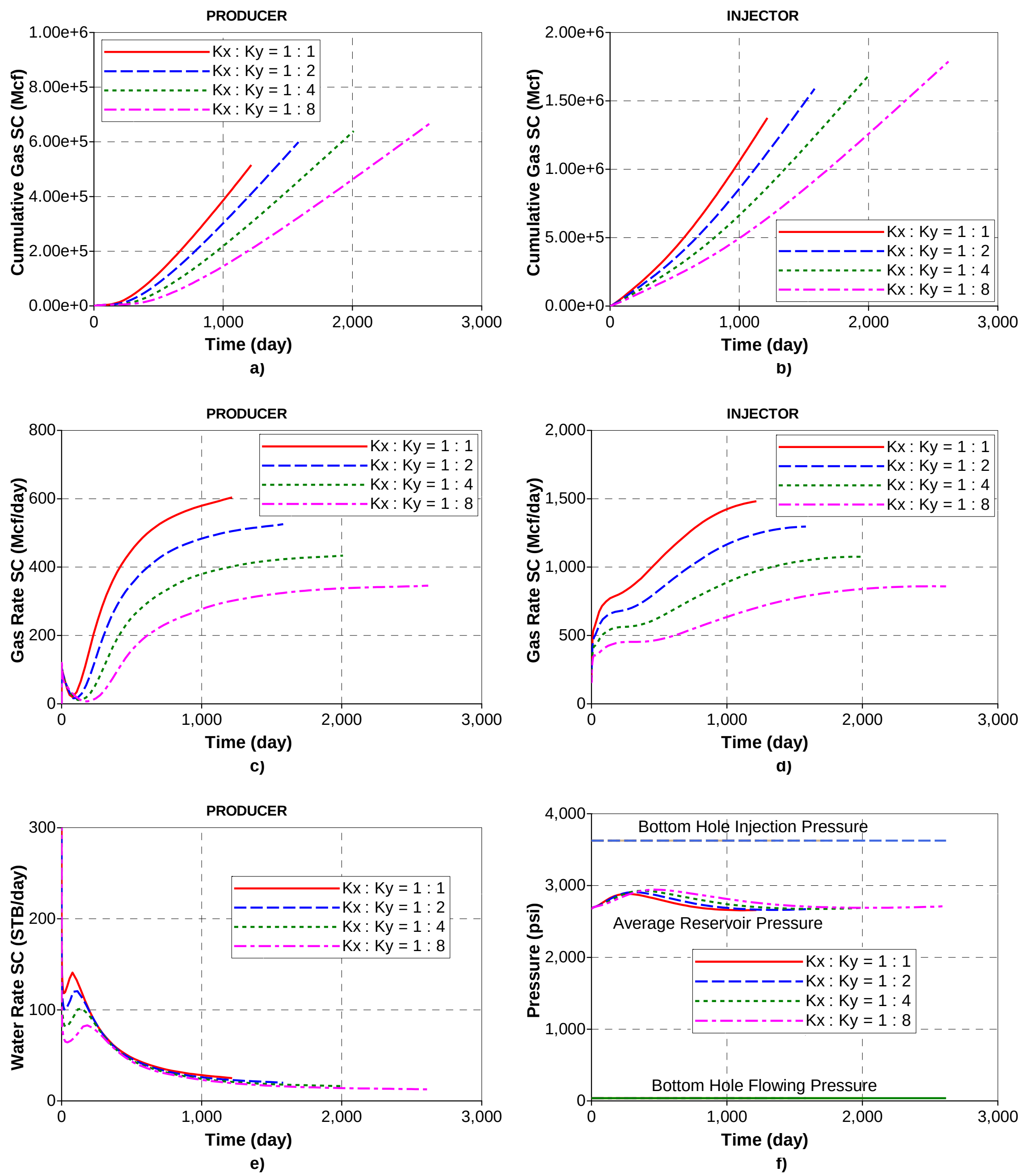


Fig. 5.22 Effect of permeability aspect ratio on a) cumulative CH_4 production, b) cumulative CO_2 injection, c) CH_4 production rates, d) CO_2 injection rates, e) water production rates, and f) average field pressure, for the 6,200-ft depth coal seam scenario and the most-likely reservoir parameters, using a parallel orientation with butt cleat permeability (k_y) aligned with the injector and producer wells, Case 6c (100% CO_2 injection). Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

5.2. Potential for CO_2 Sequestration/ECBM Production in East-Central Texas Low-Rank Coals in the Wilcox Group

Estimation of the total volumes of CO_2 that may be sequestered in, and total volumes of methane that can be produced from, the Wilcox Group low-rank coals in east-central Texas is assessed based on data obtained during this study and the probabilistic simulation modeling results for the base case coal seam scenarios at 4,000-ft and 6,200-ft depth. Table 5.1 shows the input parameters to quantify uncertainty in my forecast of these potential volumes.

Table 5.1 Parameter estimates for CBM recoverable resources and CO_2 sequestered volumes in east-central Texas.

Parameter	Value	Fitted Distribution	Parameters Distribution
Coal Thickness	10, 20, 30 ft	Normal	μ = 20, σ = 4.1
Coal Density	1591, 1644, 1704 ton/ac-ft (1.289, 1.332, 1.380 g/cm^3)	Normal	μ = 1646, σ = 23.25
Gas Content	125, 250, 300 scf/ton	Beta General	α_1 = 3.78 , α_2 = 2.06, min = 80, max = 300
CO_2 Storage (V_L, CO_2)	620, 920, 1000 scf/ton	Beta General	α_1 = 3.20, α_2 = 1.85, min = 590, max = 1000
Recovery Factor	60, 75, 80 %	Beta General	α_1 = 3.07, α_2 = 2.00, min = 0.58, max = 0.80
Injection Factor	50, 72, 75 %	Beta General	α_1 = 21.95, α_2 = 2.50, min = 0.50, max = 0.75
Area	80 acres		

I calculated an overall probabilistic estimation of the original gas in place (GIP) as the adsorbed amount of gas in the coal reservoir ignoring the amount of free gas in the fracture system, for an 80-acre 5- spot pattern, using probabilistic input parameters in the volumetric equation. Multiplying by a probability distribution for gas recovery factor from reservoir modeling studies described previously, I obtained a range of recoverable resources on a pattern basis. A similar procedure is used to calculate the maximum theoretical sequestration capacity of coal. Multiplication by an injection factor yields a range of potential CO_2 sequestered volumes on a pattern basis. I used Monte Carlo simulation of 10,000 iterations to account for uncertainty in my estimates. Table 5.2 shows the expected values of CH_4 to be produced and CO_2 to be stored in Wilcox coals, on an 80-acre 5-spot pattern basis.

Table 5.2 Expectations for CBM recoverable resources and CO_2 sequestered volumes in east-central Texas.

Recoverable Coalbed Methane Resources		**Potential Coalbed Sequestration Capacity**	
Coal Thickness, ft	20	20	Coal Thickness, ft
Coal Density, ton/ac-ft	1646	1646	Coal Density, ton/ac-ft
Gas Content, scf/ton	222	850	CO_2 Storage (V_L, CO_2), scf/ton
Pattern Area, ac	80	80	Pattern Area, ac
GIP (per 80 ac), Bcf	0.586	2.238	Theoretical Sequestration Capacity, Bcf
Recovery factor, fraction	0.713	0.724	Injection Factor, fraction
Recoverable Resources (per 80 ac), Bcf	0.418	1.621	Sequestered CO_2 Volume (per 80 ac), Bcf
Region Area, ac (2,930 sq. miles)	1,875,200	1,875,200	Region Area, ac
Number of 80-ac 5 spot patterns	23,440	23,440	Number of producer/injector wells
Potential Recoverable Resources (region area), Bcf	9,790	38,000	Potential CO_2 Seq. Volume (region area), Bcf

Fig. 5.23 shows cumulative distribution functions for GIP and recoverable resources for target coal reservoirs in the Wilcox Group in east-central Texas, and cumulative distribution functions for the theoretical sequestration capacity and potential CO_2 volumes to be stored in these coals.

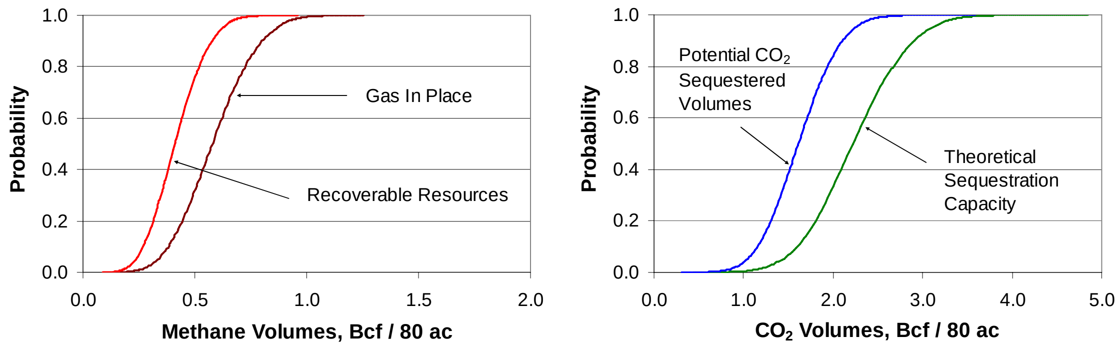


Fig. 5.23 Cumulative distribution functions for a) GIP and recoverable resources, and b) theoretical sequestration capacity and potential CO_2 sequestered volumes, for target coal reservoirs in the Wilcox Group in east-central Texas.

Table 5.3 shows the results extrapolated from an 80-acre 5-spot pattern to a regional basis (2,930 square miles, estimated target area size in east-central Texas), assuming perfect positive correlation of volumes between patterns in the region.

Table 5.3 Range of uncertainty in potential volumes of CH_4 to be produced from, and CO_2 to be sequestered in, LCB low-rank coals in the Wilcox Group in east-central Texas.

Area basis	**Total CH_4 Volumes, Bcf**			**Total CO_2 Volumes, Bcf**		
	P_{10}	Mean	P_{90}	P_{10}	Mean	P_{90}
Pattern area	0.270	0.418	0.580	1.160	1.621	2.100
East-central Texas area	6,330	9,790	13,600	27,190	38,000	49,220
East-central Texas area				**Total CO_2, MM tons**		
				1,570	2,195	2,690

There are six major power plants located in this region (Limestone 13 MM ton/yr, Sam K. Seymour 12.5 MM tons/yr, Big Brown 9.6 MM ton/yr, Sandow 4.6 MM ton/yr, Gibbons Creek 3.2 MM ton/yr, and TNP One 2.8 MM ton/yr)[9] that emit 45.7 MM tons of CO_2/year. Sequestration capacity of the LCB low rank coals in the Wilcox Group in east-central Texas equates to be between 34 and 59 years of emissions from these six power plants.

Potential recoverable methane resources from LCB low rank coals in the Wilcox Group in east-central Texas are estimated to be between 6.3 and 13.6 Tcf.

CHAPTER VI

CONCLUSIONS AND RECOMMENDATIONS

6.1. Conclusions

- Methane resources and CO_2 sequestration potential of low-rank coals of the Wilcox Group, Lower Calvert Bluff formation, in east-central Texas are significant. Resources are estimated to be between 6.3 and 13.6 Tcf of CH_4, with a potential sequestration capacity of 1,570 to 2,690 million tons of CO_2.

- Injection of 100% CO_2 in coal seams at 4,000-ft and 6,200-ft depth with average net thickness of 20 ft results in average volumes of CO_2 sequestered between 1.55 and 1.75 Bcf and average volumes of methane produced between 0.54 and 0.67 Bcf on an 80-acre 5-spot pattern basis.

- CO_2 sequestration volumes decrease and ECBM production increases with increasing N_2 content in the injected gas. Average volumes of CO_2 that may be sequestered in, and methane that can be produced from, LCB coals with average net thickness of 20 ft for 100% CO_2, 50% CO_2-50% N_2, and 13% CO_2-87% N_2 injection cases are 1.75, 1.19 and 0.46 Bcf of CO_2, and 0.67, 0.86 and 0.94 Bcf of CH_4, with project lives between 4.5, 7.5 and 11.7 years, respectively, per 80-acre 5-spot pattern.

- Well spacing sensitivity studies for 100% CO_2 injection indicate that total volumes of CO_2 sequestered and methane produced on a unit-area basis do not change significantly with spacings up to 240 acres per well.

- Gas injection rates do not appear to have a significant effect on cumulative volumes of CH_4 produced or CO_2 injected, for 100% CO_2 injection in an 80-acre 5-spot pattern at 6,200-ft depth. Longer breakthrough times were observed with lower injection rates.

- Dewatering the coals prior to starting pure CO_2 injection does not have a significant impact on reservoir performance, for an 80-acre 5-spot pattern at 6,200-ft depth.

- Anisotropic permeability sensitivity studies for 100% CO_2 injection show significant differences in the cumulative volumes of CH_4 produced and CO_2 injected due to permeability anisotropy, depending on the orientation of injection patterns relative to the orientation of permeability anisotropy.

6.2. Recommendations

- Sorptive capacity of coals greatly controls ECBM production and CO_2 storage capacity. Additional adsorption/desorption isotherms in Wilcox coals need to be measured.

- A pilot project should be implemented to further evaluate CO_2 sequestration and ECBM potential of Wilcox coals in east-central Texas.

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PROFILE

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EDUCATION

Universidad Surcolombiana. Bachelor of Science in Petroleum Engineering, July 1992.
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EXPERIENCE

Sena – Colombia. Full time instructor, 1993-1994.
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